# $NO_X$ Control Update to PPL Montana's J.E. Corette Generating Station BART Report

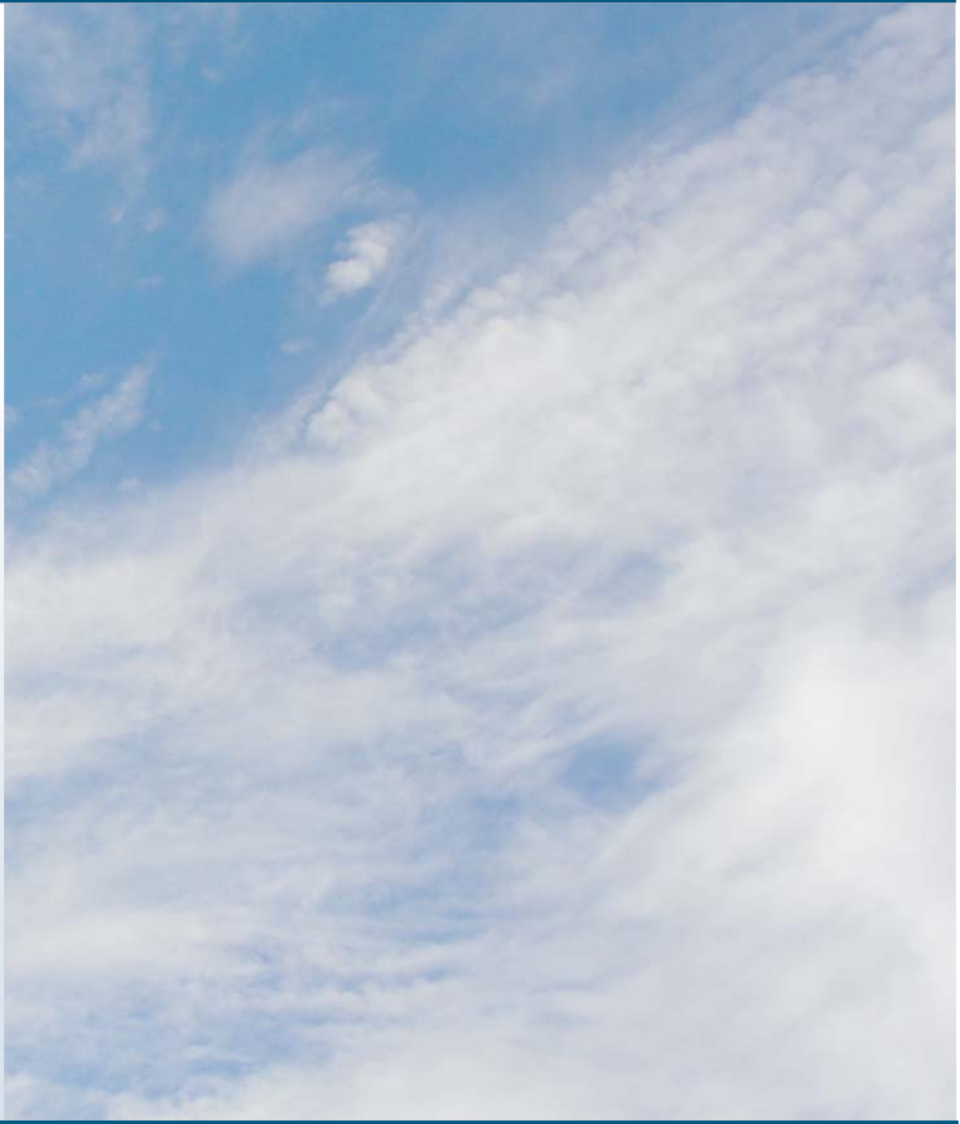
*Prepared for*

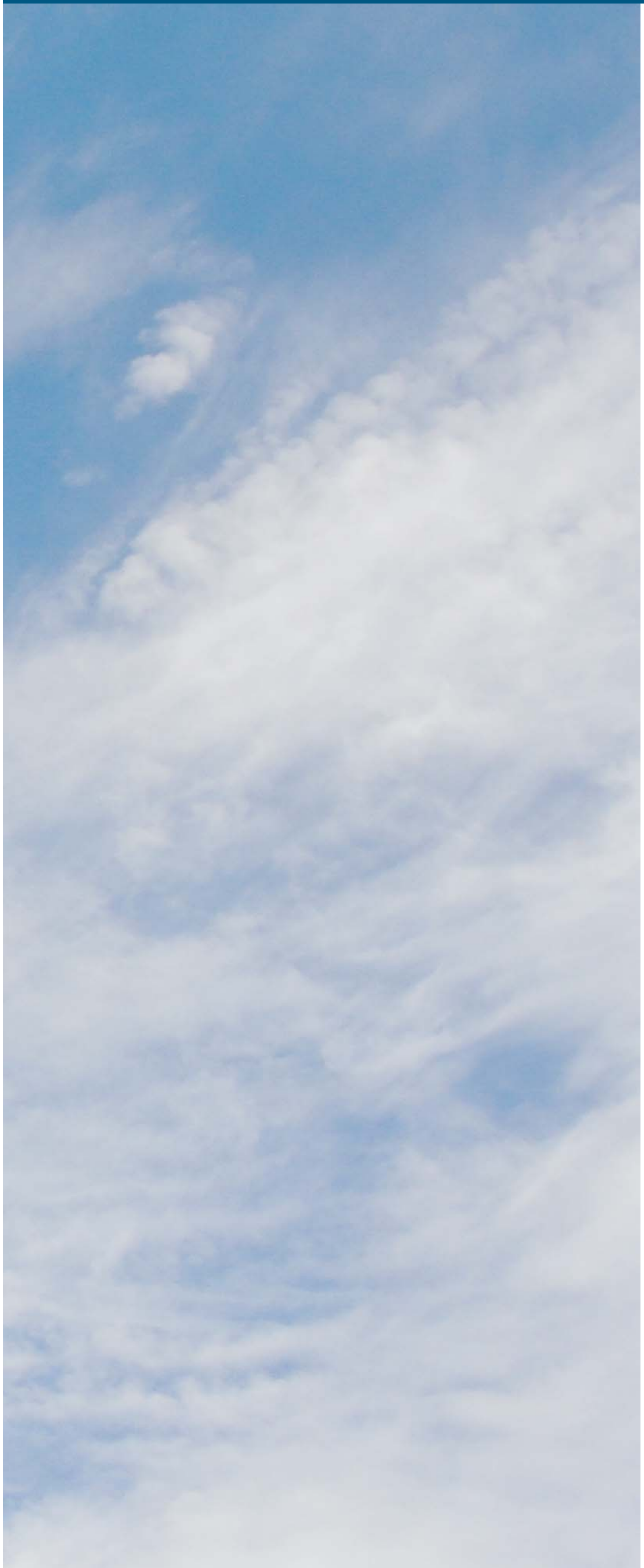
**PPL Montana, LLC**
Billings, Montana

*Prepared by*

Windsor, Connecticut

**September 2011**





# $NO_x$ Control Update to PPL Montana's J.E. Corette Generating Station BART Report

*Prepared for*

**PPL Montana, LLC**
Billings, Montana

*Prepared by*

21 Griffin Road North
Windsor, Connecticut 06095
Telephone 860-298-9692
Facsimile 860-298-6399

TRC Project No. 184990

**September 2011**

## EXECUTIVE SUMMARY

As part of the Best Available Retrofit Technology (BART) assessment for the J.E. Corette (Corette) coal-fired steam electric plant, an economic cost effectiveness analysis was performed in an initial report dated August 2007. Upon review and comment by the U.S. Environmental Protection Agency Region 8, the initial analysis was updated in an addendum report dated June 2008. On May 18, 2011, EPA requested any further updates to these previously submitted BART reports for Corette which PPL Montana believes necessary. This report is a $NO_x$ control update to the initial reports.

The Corette power plant, located in Billings, Montana, is owned and operated by PPL Montana, LLC. The coal-fired boiler at the plant was determined to be BART-eligible under the Federal Regional Haze Rule by the U.S. Environmental Protection Agency Region 8. It is a 162 MW electrical generation unit that burns low sulfur sub-bituminous coal.

Since the previous BART reports were prepared, new cost analysis techniques have been developed as part of the Integrated Planning Model (the IPM) under a grant from the U.S. EPA, "Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model". See the following link for more details:

http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation)

ICF International (ICF) developed IPM to assess the combined effect that air rules have on the utility industry as a whole. This platform has also been used by EPA's Clean Air Markets Division for analyzing recent air policy decisions. Based upon currently available information, the control technology cost estimation techniques developed for the IPM appear to be more robust than those used in the previous BART reports prepared by PPL Montana. The IPM includes cost updating to reflect significant increases in material and labor costs. In addition, we have incorporated cost updates available from PPL's direct and indirect experiences. These costs reflect our best high level estimate based on the data currently available. This updated assessment has been prepared to incorporate IPM cost analysis techniques and update the cost effectiveness (CE) calculations from the referenced previous BART reports in response to a May 18, 2011 request by EPA for any necessary BART analysis updates.

Consistent with the June 2008 Addendum, TRC estimated costs for the control technologies evaluated based on typical emission rates representative of a 30-day average and the maximum 24-hour emission rates based on data during the modeling years (2001, 2002 & 2003) as requested by EPA. Even though PPL Montana believes that the actual cost effectiveness should be based on a longer time basis utilizing typical emission rates (30-day average at a minimum) and that a shorter time basis and maximum emission rates are not representative of site-specific cost effectiveness, we are providing the 24-hour cost calculation as requested. The 30-day running average baseline $NO_x$ emission rate is 0.26 lbs $NO_x$/MMBtu and the 24-hour baseline emission rate is 0.31 lbs $NO_x$ /MMBtu.

For this updated assessment, we have evaluated three technologies for cost effectiveness in reducing nitrogen oxides ($NO_x$) emissions: (1) combustion controls, (2) Selective Non-Catalytic Reduction or SNCR, and (3) Selective Catalytic Reduction or SCR. The results of the control cost assessment based on the IPM costing approach for the three control options are discussed below. The details of the CE calculations for each control technology are provided in Section 4 and the associated tables.

The Corette boiler is currently operated with $NO_x$ combustion control technology utilizing low $NO_x$ burners, close coupled overfire air, and digital controls[1]. Modifying these combustion controls through the installation of separated overfire air and more sophisticated burner controls (SOFA system)[2] is projected to reduce the $NO_x$ emission rate to 0.20 lbs/MMBtu. This value is used as the baseline for cost effectiveness calculations because the addition of SOFA would, of necessity, accompany installation of any additional controls. The two reagent injection technologies, SNCR and SCR involve the injection of quantities of a $NO_x$ reducing agent into the exhaust for the conversion of $NO_x$ to nitrogen and water vapor. Typically either urea or aqueous ammonia is the reagent used. The reagent is injected at amounts higher than required for reaction and results in residual ammonia in the exhaust known as ammonia slip. SNCR is a post combustion technology in which ammonia or urea is injected into the combustion zone of the boiler to chemically reduce $NO_x$ to nitrogen and water vapor, and carbon dioxide if urea serves as the source of ammonia. With SNCR, it is expected that a 10% incremental reduction of $NO_x$ over that attained by modified combustion controls alone could be achieved, resulting in an estimated $NO_x$ emission rate of 0.185 lbs/MMBtu. While an estimated additional 113 tons per year of $NO_x$ would be reduced over the combustion controls and digital process controls, an estimated ammonia slip of 38 tons per year would contribute to fouling and pluggage of the economizer and air preheater and be emitted from the stacks negating at least a portion of any visibility benefits from the $NO_x$ reduction. Fouling downstream of ammonia injection has been reported as an operating and maintenance concern in applications of this technology by other facilities. Consequently, PPL Montana expects that increased costs will occur at the plant to address higher fouling of components, increased maintenance, and a resultant increase in forced outages. Increased forced outages to perform necessary maintenance activities would significantly increase the cost of this technology. Even a one-day maintenance outage would increase the cost of this technology by approximately $2,055/ton.

Selective Catalytic Reduction (SCR) technology also uses urea or ammonia injection. However, that injection occurs upstream of a catalyst that produces higher reduction efficiencies. SCRs have a

---

[1] Alstom LNCFS Level II® system

[2] Alstom LNCFS Level III® system

significantly higher capital cost and have comparatively lower ammonia slip. In the case of application of SCR, the $NO_x$ controls would be located after the economizer and upstream of the air preheater and precipitator. The addition of SCR technology is estimated to reduce $NO_x$ emissions to an estimated 0.06 lbs/MMBtu from the significant reductions already attained by combustion controls.

Each add-on post combustion control technology would have significant impacts at the plant. The estimated ammonia slip likely would contribute to fouling and pluggage of the economizer and air preheater and be emitted from the stacks and contribute to a visible plume. Furthermore, there would be cost impacts due to the limited available space. Reagent preparation equipment, reagent receipt, loading and unloading equipment, and the reactors for SCR would present significant construction and operational difficulties, due to limited space.

The estimated cost effectiveness of modified combustion controls (SOFA system) is approximately $1,809 per ton of $NO_x$ removed on an annualized basis. The cost effectiveness of SNCR is approximately $13,544 per ton of $NO_x$ removed on an annualized basis. This estimate includes increased maintenance costs to address the fouling downstream of ammonia injection, but does not include any other costs related to increased forced outages, such as lost generation, which would involve additional costs. As noted above, even a one-day maintenance outage would increase the cost of SNCR technology by approximately $2,055/ton.

The estimated cost effectiveness for the addition of SCR to Corette is approximately $8,457/ton of additional $NO_x$ controlled. This does not include any increased cost as a result of an increase in forced outage rate. Even a one-day maintenance outage would increase the cost by approximately $220/ton.[3]

For this report, PPL Montana determined that it was not necessary to update any of the June 2008 visibility assessments as the range of $NO_x$ emission reductions achieved by the evaluated control technologies in this addendum is within the range of $NO_x$ reductions previously evaluated. The high cost per ton of additional $NO_x$ removal with these technologies leads to the conclusion that these are not appropriate technologies for retrofit application to Corette. In addition, we believe that no significant visibility benefit is expected from the emission reductions that these technologies would achieve.

---

[3] This is less than the equivalent forced outage cost for an SNCR as the SCR removes more tons of $NO_x$.

## TABLE OF CONTENTS

SECTION PAGE

TABLES

## 1.0 RECENT DEVELOPMENTS IN CONTROL TECHNOLOGY COST ANALYSIS

When the final rule was promulgated in 2005 (see FR Vol. 70, No. 128, July 6, 2005), much of the then available Air Pollution Control Equipment (APCE) cost data were contained in the USEPA Control Cost Manual (the CCM)[4] published in January 2002. For $NO_x$, the electric utility control costing techniques were limited to Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). Utility applications of combustion controls were installed and operating in the USA, however, no compilation of the cost of such utility sized systems was available other than as provided in the CCM.

Using costing tools available at that time, analyses of BART were submitted to regional offices of USEPA as required and reviews of the reports, such as those submitted by PPL Montana in August 2007 and subsequently amended in 2008, were performed. Simultaneously, however, EPA was utilizing available planning tools to study the universe of environmental effects that rules such as the Clean Air Interstate Rule (CAIR), Best Available Retrofit Technology (BART), and other local rules would have on the utility industry in the USA. One such tool used by EPA is the Integrated Planning Model or the IPM. ICF International (ICF) developed the IPM to assess the combined effect that air rules have on the electric utility industry as a whole. This platform has also been used by EPA's Clean Air Markets Division for analyzing recent air policy decisions. Based upon currently available information, the control technology cost estimation techniques developed for the IPM appear to be more robust than earlier cost analysis methods.

### 1.1 Reduction of $NO_x$ Using Combustion Controls

The IPM includes cost estimating methodology for the various low-$NO_x$ burner and overfire air combustion control options. For a tangentially fired boiler such as that at Corette, cost estimation methods and empirical equations for low $NO_x$ coal-and-air nozzles with close coupled and separated overfire air are also included. The Corette boiler is currently operated with $NO_x$ combustion control technology utilizing low $NO_x$ burners, close coupled overfire air, and digital controls[5] and already has a relatively low $NO_x$ emission rate without application of any additional combustion controls. Modifying the combustion controls is possible through the installation of separated overfire air and more sophisticated burner controls (SOFA system)[6], but the ability of the SOFA system to reduce emissions from the current level of 0.26 lbs/MMBtu is limited to a reduction of no more than about 23%, resulting in an estimated emission rate of 0.20 lbs/MMBtu.

---

[4] - EPA control Cost Manual, 6th ed., EPA-452-01-001, January 2002

5 Alstom LNCFS Level II® system

6 Alstom LNCFS Level III® system

### 1.2 Selective Non-Catalytic Reduction of $NO_x$

SNCR is a post combustion technology in which ammonia or urea is injected into the combustion zone of the boiler where the temperature is in a range of 1600 deg F to 2000 deg F. It is called “post combustion” because, unlike the control options that prevent or reduce the formation of thermal and fuel $NO_x$, SNCR injects a chemical to chemically reduce $NO_x$ to nitrogen and water vapor (and carbon dioxide if urea serves as the source of ammonia). The chemical reactions, which are not presented here, occur between nitric oxide (NO) and ammonia, i.e., $NH_3$ or $CO(NH_2)_2$ to form carbon dioxide, water vapor, and nitrogen. Not all of the injected ammonia results in $NO_x$ reduction reactions. Unreacted ammonia may react with $SO_2$ or $SO_3$ to form ammonium bisulfite and/or ammonium sulfate which will contribute to fouling economizer and air preheater surfaces and also contribute to plume visibility concerns. The application of this technique involves injecting the reactant in a stream of water or steam into a region in the boiler where reaction temperatures are in the correct range. Multiple injectors are typically utilized and the technique can provide 35% reduction in the $NO_x$. Greater reductions are limited by the low $NO_x$ emissions rate already being achieved at Corette.

Operation of SNCR also results in ammonia slip. Ammonia slip is residual ammonia that does not react with $NO_x$ and typically this can be limited to about 10 parts per million by volume (ppmv). This would result in approximately 10 pounds per hour (38 tons per year) of unreacted ammonia, which can cause adverse visibility impacts. In SNCR the reactive reagent, in this case urea, would be injected into the combustion zone of the boiler and react with $NO_x$. In addition, there is likely to be significant fouling of the economizer and air heater surfaces. These impacts would require increased maintenance activities for cleaning the ammonium bisulfite and sulfate ammonia slip byproducts from the economizer and air preheater surfaces, which would likely result in an increase in forced outages.

### 1.3 Selective Catalytic Reduction

In SCR technology, the exhaust is also injected with ammonia or urea, however the reactant is injected upstream of a bed of catalyst that is utilized to allow the reactions to occur at lower temperatures. The more intimate contact between the exhaust and the reagent in the catalyst bed also produces higher reduction efficiencies. While SCR will perform better than SNCR with the already low $NO_x$ emission rate, the lowest emission rate attainable with the 0.20 lbs/MMBtu at Corette is expected to be 0.06 lbs/MMBtu, or about a 70% reduction.

Operation of the SCR also results in ammonia slip. Just as in SNCR, a slight excess of reagent is required to reduce $NO_x$ emissions and both technologies are expected to have ammonia slip emissions. The location of the SCR unit would be downstream of the economizer and upstream of the air heater and precipitator. While ammonia slip from SCR should be lower than with SNCR, increased forced outages to address downstream sulfite/sulfate fouling impacts from byproducts of ammonia slip could occur.

## 2.0 COMBUSTION CONTROLS, SNCR AND SCR COSTING USING THE IPM METHODOLOGY

ICF International (ICF) developed a proprietary tool known as the IPM to assess the combined effect that air rules have on the utility industry as a whole. This platform has also been used by EPA's Clean Air Markets Division for analyzing air policy decisions. One aspect of the IPM is the capital, operating, and maintenance cost of air pollution control equipment. These costing analytical techniques were summarized in reference 1, available from the US EPA Clean Air Markets Division or through the link provided in the executive summary of this report. For $NO_x$, APCE cost analyses for the combustion controls, and for the two add-on, i.e. post combustion, control technologies are presented; SNCR, and SCR.

Pages 5-7 and 5-8 from the documentation document for the IPM model are presented in Attachment A-1. The data in Table 5-5 summarizes the costs for the several combustion controls techniques in 2007 dollars. While the costs are presented for a 300 MW coal fired boiler, scaling factors are included that allow the cost data to be scaled to any coal fired boiler greater than 25 MW in gross power output. Table 5-7 lists the assumptions used in the IPM model for NOx emission control efficiencies for SNCR and SCR technologies.

Two additional background reports are included in Attachment A, which describe the costing approach to SNCR and SCR. Each report was prepared by Sargent & Lundy, LLC under contract to the USEPA. Based upon a proprietary database of control installation costs, this engineering firm developed empirical equations which were used to estimate the costs of controls as applied to all types of coal-fired boiler plants. This costing aspect of the IPM allowed analysis of the effect of rules such as BART on the utility generating fleet.

The cost equations developed for the IPM contain both capital and operating and maintenance costs. Just as EPA used cost factors as percentages of the capital equipment cost, S&L used the same approach to develop their capital costs for an installed retrofit project. More details regarding this approach are provided in Attachments A-2 and A-3.

### 2.1 Combustion Controls Cost Analysis Using the IPM Methodology

As shown in Attachment A-1, Table 5-5, there are several combustion controls options for tangentially-fired coal boilers like the boiler at Corette. PPL Montana used the cost data for Low-$NO_x$ Coal- and Air Nozzles with Close-Coupled and Separated Overfire Air which would be similar to those installed and in operation at other PPL plants. Due to the already low emission rate of $NO_x$ at Corette resulting from the combustion controls already installed, only a 23% reduction is expected by application from application of an updated combustion control technology. Detailed cost calculations are presented in Tables 2-1a and 2-1b.

## 2.2 SNCR Cost Analysis Using the IPM Methodology

Tables 2-2a through 2-2d show the results of application of the costing methodology developed for use by EPA in the IPM regulatory studies. Tables 2-2a and 2-2c present the Corette specific parameters for the boiler applied within the empirical cost analysis approach developed by S&L as presented in Attachment A-2. The use of the "retrofit factor" is provided in the analytical cost equations to allow for particularly difficult sites where application of retrofit technology would be more difficult due to site specific factors. PPL Montana believes that the limited space available for the installation of reagent preparation equipment and reagent receipt and unloading operations will make the application of SNCR difficult at the Corette site. PPL Montana has used a factor of 2.0 instead of the 1.0 that would characterize a more open site plan than that available at Corette. Tables 2-2b and 2-2d show the calculations of the $/ton of $NO_x$ for SNCR.

SNCR uses urea that is injected into the combustion zone where it breaks down into two moles of ammonia and one mole of $CO_2$ per mole of urea injected. Excess reagent is always required to attain acceptable $NO_x$ reductions; however, the reductions that are attainable are higher when the uncontrolled $NO_x$ is higher. At a typical ammonia slip concentration in the exhaust of 10 ppm, the unreacted ammonia would lead to higher fouling of economizer, air preheater and electrostatic precipitator resulting in increased maintenance and outages. Using the IPM methodology, and assuming that installation of an SNCR will result in an emission rate of 0.185 lbs/MMBtu the cost effectiveness is estimated to be $13,544/ton. This does not include cost of lost generation for an increase in outages. Even a one-day maintenance outage would increase the cost by approximately $2,055/ton.

## 2.3 SCR Cost Analysis Using the IPM Methodology

Tables 2-3a through and 2-3d show the results of application of the S&L costing methodology to Corette for SCR. The costs reflected in these tables reflect a retrofit factor of 2.0 based on PPL experience in estimating a retrofit of an SCR on a large coal-fired unit. Residual ammonia in the exhaust (expected to be at about 2 ppmv) although less than that associated with SNCR, is likely to react with other components of the exhaust to generate additional fine particulates, or require increased maintenance to address other downstream impacts on equipment. Application of SCR at Corette is estimated to cost $8,457/ton assuming an emission rate of 0.06 lbs/MMBtu. This does not include any increased cost as a result of lost generation from an increase in forced outage rate. Even a one-day maintenance outage would increase the cost by approximately $220/ton.[7]

---

[7] This is less that the equivalent forced outage cost for an SNCR as the SCR removes more tons of $NO_x$.

## 3.0 CONCLUSION

Based on the high cost per ton of the estimated $NO_x$ removed through installation of any of these $NO_x$ reduction technologies at Corette, these controls are not appropriate and further analysis is not warranted. In addition, no significant visibility benefit is expected from the emission reductions resulting from these technologies. For this report, PPL Montana determined that it was not necessary to update any of the June 2008 visibility assessments as the range of $NO_x$ emission reductions achieved by the evaluated control technologies in this addendum is within the range of $NO_x$ reductions previously evaluated. The additional analysis provided by this addendum does not change the conclusion that PPL Montana reached for the Corette boiler in its August 2007 BART Assessment or the June 2008 Addendum that implementation of further $NO_x$ controls is not warranted.

# Table 2-1a
# PPL BART Cost Effectiveness Analysis
# Combustion Controls for NOx
# 162 Megawatt Coal Fired Steam Electric Plant
# Corette - 30 Day Average NOx

| | | |
|---|---|---|
| Maximum Gross Heat Input | MM Btu/hr | 1,941 |
| Design Percent Load | % | 89 |
| Uncontrolled NOx Emissions | lbs/MMBtu | 0.260 |
| ExhaustTemperature, ($^{o}$F) | T | 405 |
| Steam Turbine Power Output (TMW) | MW | 162 |
| Capacity Factor (89%) | hrs | 7,796 |
| Controlled NOx Emissions | lbs/MMBtu | 0.20 |
| Overall NOx Reduction Efficiency, (%) | % | 23 |
| Uncontrolled NOx Emissions, (lb/hr) | | 504.7 |
| Uncontrolled NOx Emissions, (tons/yr) | | 1967.3 |
| Controlled NOx Emissions, (ton/yr) | | 1513.3 |
| Annual Interest Rate, (%) | | 7 |
| Equipment Life, (yrs) | yr | 20 |
| Capital Recovery Factor, CRF | CRF | 0.0944 |

| Cost Item | Suggested Factor | Unit Cost | Item Cost |
|---|---|---|---|
| From EPA Documentation Study (Reference 1) | Capital Cost ($/KW) | 38 | $7,680,142 |
| Equipment Cost Total, (EC) | EC (Adjusted by Cost Index Calcs) | (2011 dollars)$^{(2)}$ | $8,186,563 |
| **Total Capital Costs, TCC** | | --- | $8,186,563 |
| **Direct Annual Costs, DAC** | | | |
| | Fixed O& M Costs | 0.3 $/kW-yr | $48,600 |
| **Total Direct Annual Costs, DAC** | | | $48,600 |
| **Indirect Annual Costs** | | | |
| Capital Recovery | CRF*TCC | --- | $772,754 |
| **Total Indirect Annual Costs, IAC** | | | $772,754 |
| **Total Annual Costs, TAC = DAC + IAC** | | | $821,354 |
| **Cost Effectiveness ($/ton pollutant Removed)** | | | $1,809 |

Cost data references:

1) Cost analysis equations from "Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, " August 2010, pg 5-7
2) Cost indices used to adjust 2007 costs to 2011 costs (2007 CI= 106.098, 2011 CI= 113.094)

# Table 2-1b
# PPL BART Cost Effectiveness Analysis
## Combustion Controls for NOx
## 162 Megawatt Coal Fired Steam Electric Plant
## Corette 24 Hour Average NOx

| | | |
|---|---|---|
| Maximum Gross Heat Input | MM Btu/hr | 1,941 |
| Design Percent Load | % | 89 |
| Uncontrolled NOx Emissions | lbs/MMBtu | 0.310 |
| ExhaustTemperature, ($^o$F) | T | 405 |
| Steam Turbine Power Output (TMW) | MW | 162 |
| Capacity Factor (89%) | hrs | 7,796 |
| Controlled NOx Emissions | lbs/MMBtu | 0.24 |
| Overall NOx Reduction Efficiency, (%) | % | 23 |
| Uncontrolled NOx Emissions, (lb/hr) | | 601.7 |
| Uncontrolled NOx Emissions, (tons/yr) | | 2345.6 |
| Controlled NOx Emissions, (ton/yr) | | 1806.1 |
| Annual Interest Rate, (%) | | 7 |
| Equipment Life, (yrs) | yr | 20 |
| Capital Recovery Factor, CRF | CRF | 0.0944 |

| Cost Item | Suggested Factor | Unit Cost | Item Cost |
|---|---|---|---|
| From EPA Documentation Study (Reference 1) | Capital Cost ($/KW) | 38 | $7,680,142 |
| Equipment Cost Total, (EC) | EC (Adjusted by Cost Index Calcs) | (2011 dollars)$^{(2)}$ | $8,186,563 |
| **Total Capital Costs, TCC** | | --- | $8,186,563 |
| **Direct Annual Costs, DAC** | | | |
| | Fixed O& M Costs | 0.3 $/kW-yr | $48,600 |
| **Total Direct Annual Costs, DAC** | | | $48,600 |
| **Indirect Annual Costs** | | | |
| Capital Recovery | CRF*TCC | --- | $772,754 |
| **Total Indirect Annual Costs, IAC** | | | $772,754 |
| **Total Annual Costs, TAC = DAC + IAC** | | | $821,354 |
| **Cost Effectiveness ($/ton pollutant Removed)** | | | $1,522 |

Cost data references:

1) Cost analysis equations from "Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, " August 2010, pg 5-7

2) Cost indices used to adjust 2007 costs to 2011 costs (2007 CI= 106.098, 2011 CI= 113.094)

# Table 2-2a
# SNCR COSTING DEVELOPMENT
# FOR CAPITAL AND OPERATION AND MAINTENANCE COSTS

| Variable | Designation | Units | Value | Equation/Input(1) |
|---|---|---|---|---|
| **SNCR CAPITAL COST FOR CORETTE - 30 DAY AVERAGE NOx** | | | | |
| Unit Capacity (Gross) | A | (MW) | 162 | Input |
| Retrofit Factor | B | | 2 | Difficulty of Retrofit |
| Gross heat rate | C | Btu/KW-hr | 11,982 | Input |
| NOx Emiss Rate | D | lbs/MMBtu | 0.2 | Uncontrolled |
| $SO_2$ Emiss Rate | E | lbs/MMBtu | 0.6 | Input |
| Type of Coal | E | PRB | | Input |
| Coal Factor | F | 1 | 1 | Input |
| Heat Rate Factor | G | 1 | 1 | C / 10,000 |
| Heat Input | H | Btu/hr | 1.94E+09 | A X C x 1000 |
| Capacity Factor | I | (%) | 89.0 | Input |
| NOx Removal Eff | J | (%) | 10.00 | Input |
| NOx Removed | K | (lbs/hr) | 38.82 | D x H/$10^6$ x J/10 |
| Urea Rate | L | (lbs/hr) | 168.79 | K /0.15/46 x 30 |
| Water Required | M | (lbs/hr) | 1519.11 | L x 9 |
| Dilution Water Rate | O | (1,000 gph) | 0.18 | M x 0.12/1000 |
| Urea Cost 50% wgt Soln | P | ($/ton) | 450 | Input |
| Dilution Water Cost | R | ($/kgal) | 1 | Input |
| Operating Labor Rate | S | ($/hr) | 60 | Input |
| **CAPITAL EQUIPMENT COSTS** | | | | |
| SNCR Injectors, DCS | BMS | ($) | $3,227,506 | B x F/1.05 x 200000 x $(AxG)^{0.42}$ |
| Air Heater Mods (not reqd) | BMA | ($) | $0 | |
| Balance of Plant Costs | BMB | ($) | $2,244,877 | 270000 x $A^{0.33}$ x $K^{0.12}$ |
| Bare Module Cost | BM | ($) | $5,472,383 | BMS + BMA + BMB |
| Engineering, Const Mgmt | A1 | ($) | $547,238 | 10% of BM |
| Labor Adjustment | A2 | ($) | $547,238 | 10% of BM |
| Contractor Profit, Fees | A3 | ($) | $547,238 | 10% of BM |
| Cap, Eng, Const Cost | CECC | ($) | $7,114,098 | BM + A1 + A2 + A3 |
| Owners Cost | B1 | ($) | $355,705 | 5% of CECC |
| Total Project Cost | TPC | ($) | $7,469,803 | CECC + B1 |
| Cost per kW | | ($) | 46 | $/kW |
| **OPERATING AND MAINTENANCE COSTS** | | | | |
| Fixed Operator Cost | FOMO | ($) | $62,400 | 2,080 hrs- 1- half time |
| Maintenance Material | FOMM | ($) | $65,669 | 1.2% of BM |
| Total Fixed O&M | | ($) | $128,069 | FOMO + FOMM |
| Urea Cost | VOMR | ($) | $37.98 | L x P |
| Dilution Water Cost | VOMM | ($) | $0.18 | O x R |

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SNCR Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

# Table 2-2b
# PPL BART Cost Effectiveness Analysis
# SNCR NOx Control
# 162 Megawatt Coal Fired Steam Electric Plant
# Corette - 30 Day Average NOx

| | | | |
|---|---|---|---|
| Maximum Gross Heat Input | MM Btu/hr | | 1,941 |
| Design Percent Load | % | | 89 |
| Uncontrolled NOx Emissions (with PRB coal) | lbs/MMBtu | | 0.200 |
| ExhaustTemperature, ($^{o}$F) | T | | 405 |
| Steam Turbine Power Output (TMW) | MW | | 162 |
| Capacity Factor (89%) | hrs | | 7,796 |
| Controlled NOx Emissions | lbs/MMBtu | | 0.185 |
| Overall NOx Reduction Efficiency, (%) | % | Note 3 | 7.50 |
| Uncontrolled NOx Emissions, (lb/hr) | | | 388.2 |
| Uncontrolled NOx Emissions, (tons/yr) | | | 1513.3 |
| Controlled NOx Emissions, (ton/yr) | | | 1399.8 |
| Annual Interest Rate, (%) | | | 7 |
| Equipment Life, (yrs) | yr | | 20 |
| Capital Recovery Factor, CRF | CRF | | 0.0944 |

| Cost Item | Suggested Factor | Unit Cost | Item Cost |
|---|---|---|---|
| IPM Model, August 20, 2010(1) | Capital Cost ($/KW) | 46 | $7,469,803 |
| Equipment Cost Total, (EC) | EC (Adjusted by Cost Index Calcs) | (2011 dollars)(2) | $7,708,359 |
| **Total Capital Costs, TCC** | | --- | $7,708,359 |
| **Direct Annual Costs, DAC** | Urea Cost | VOMR | $296,090 |
| | Dilution Water Cost | VOMM | $1,421 |
| | Maintenance Labor | FOMO | $62,400 |
| | Air Preheater Cleaning | 4 at $96,000 each | $384,000 |
| | Maintenance Materials | FOMM | $65,669 |
| **Total Direct Annual Costs, DAC** | | | $809,579 |
| **Indirect Annual Costs** | | | |
| Capital Recovery | CRF*TCC | --- | $727,615 |
| **Total Indirect Annual Costs, IAC** | | | $727,615 |
| **Total Annual Costs, TAC = DAC + IAC** | | | $1,537,194 |
| **Cost Effectiveness ($/ton pollutant Removed)** | | | $13,544 |

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SNCR Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) Cost indices used to adjust 2009 costs to 2011 costs (2009 CI= 109.594, 2011 CI= 113.094)
3) The controlled NOx emissions are adjusted to account for 38 tons of ammonia slip assuming that ammonia emissions are equivalent to NOx emissions on a ton for ton basis.

# Table 2-2c
# SNCR COSTING DEVELOPMENT
# FOR CAPITAL AND OPERATION AND MAINTENANCE COSTS

| Variable | Designation | Units | Value | Equation/Input(1) |
|---|---|---|---|---|
| **SNCR CAPITAL COST FOR CORETTE - 24 HOUR AVERAGE NOx** | | | | |
| Unit Capacity (Gross) | A | (MW) | 162 | Input |
| Retrofit Factor | B | | 2 | Difficulty of Retrofit |
| Gross heat rate | C | Btu/KW-hr | 11,982 | Input |
| NOx Emiss Rate | D | lbs/MMBtu | 0.26 | Uncontrolled |
| $SO_2$ Emiss Rate | E | lbs/MMBtu | 0.6 | Input |
| Type of Coal | E | PRB | | Input |
| Coal Factor | F | 1 | 1 | Input |
| Heat Rate Factor | G | 1 | 1 | C / 10,000 |
| Heat Input | H | Btu/hr | 1.94E+09 | A X C x 1000 |
| Capacity Factor | I | (%) | 89.0 | Input |
| NOx Removal Eff | J | (%) | 10.00 | Input |
| NOx Removed | K | (lbs/hr) | 50.47 | D x H/$10^6$ x J/10 |
| Urea Rate | L | (lbs/hr) | 219.43 | K /0.15/46 x 30 |
| Water Required | M | (lbs/hr) | 1974.84 | L x 9 |
| Dilution Water Rate | O | (1,000 gph) | 0.24 | M x 0.12/1000 |
| Urea Cost 50% wgt Soln | P | ($/ton) | 450 | Input |
| Dilution Water Cost | R | ($/kgal) | 1 | Input |
| Operating Labor Rate | S | ($/hr) | 60 | Input |
| **CAPITAL EQUIPMENT COSTS** | | | | |
| SNCR Injectors, DCS | BMS | ($) | $3,227,506 | B x F/1.05 x 200000 x $(AxG)^{0.42}$ |
| Air Heater Mods (not reqd) | BMA | ($) | $0 | |
| Balance of Plant Costs | BMB | ($) | $2,316,679 | 270000 x $A^{0.33}$ x $K^{0.12}$ |
| Bare Module Cost | BM | ($) | $5,544,184 | BMS + BMA + BMB |
| Engineering, Const Mgmt | A1 | ($) | $554,418 | 10% of BM |
| Labor Adjustment | A2 | ($) | $554,418 | 10% of BM |
| Contractor Profit, Fees | A3 | ($) | $554,418 | 10% of BM |
| Cap, Eng, Const Cost | CECC | ($) | $7,207,440 | BM + A1 + A2 + A3 |
| Owners Cost | B1 | ($) | $360,372 | 5% of CECC |
| Total Project Cost | TPC | ($) | $7,567,812 | CECC + B1 |
| Cost per kW | | ($) | 47 | $/kW |
| **OPERATING AND MAINTENANCE COSTS** | | | | |
| Fixed Operator Cost | FOMO | ($) | $62,400 | 2,080 hrs- 1- half time |
| Maintenance Material | FOMM | ($) | $66,530 | 1.2% of BM |
| Total Fixed O&M | | ($) | $128,930 | FOMO + FOMM |
| Urea Cost | VOMR | ($) | $49.37 | L x P |
| Dilution Water Cost | VOMM | ($) | $0.24 | O x R |

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SNCR Cost Development Methodology-FINAL", August 2010

Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

## Table 2-2d
## PPL BART Cost Effectiveness Analysis
## SNCR NOx Control
## 162 Megawatt Coal Fired Steam Electric Plant
## Corette 24 Hour Average NOx

| | | | |
|---|---|---|---|
| Maximum Gross Heat Input | MM Btu/hr | | 1,941 |
| Design Percent Load | % | | 89 |
| Uncontrolled NOx Emissions (with PRB coal) | lbs/MMBtu | | 0.260 |
| ExhaustTemperature, ($^{o}$F) | T | | 405 |
| Steam Turbine Power Output (TMW) | MW | | 162 |
| Capacity Factor (89%) | hrs | | 7,796 |
| Controlled NOx Emissions | lbs/MMBtu | | 0.24 |
| Overall NOx Reduction Efficiency, (%) | % | Note 3 | 8.08 |
| Uncontrolled NOx Emissions, (lb/hr) | | | 504.7 |
| Uncontrolled NOx Emissions, (tons/yr) | | | 1967.3 |
| Controlled NOx Emissions, (ton/yr) | | | 1808.4 |
| Annual Interest Rate, (%) | | | 7 |
| Equipment Life, (yrs) | yr | | 20 |
| Capital Recovery Factor, CRF | CRF | | 0.0944 |

| Cost Item | Suggested Factor | Unit Cost | Item Cost |
|---|---|---|---|
| IPM Model, August 20, 2010(1) | Capital Cost ($/KW) | 47 | $7,567,812 |
| Equipment Cost Total, (EC) | EC (Adjusted by Cost Index Calcs) | (2011 dollars)(2) | $7,809,498 |
| **Total Capital Costs, TCC** | | --- | $7,809,498 |
| **Direct Annual Costs, DAC** | Urea Cost | VOMR | $384,916 |
| | Dilution Water Cost | VOMM | $1,848 |
| | Maintenance Labor | FOMO | $62,400 |
| | Air Preheater Cleaning | 4 at $96,000 each | $384,000 |
| | Maintenance Materials | FOMM | $66,530 |
| **Total Direct Annual Costs, DAC** | | | $899,694 |
| **Indirect Annual Costs** | | | |
| Capital Recovery | CRF*TCC | --- | $737,161 |
| **Total Indirect Annual Costs, IAC** | | | $737,161 |
| **Total Annual Costs, TAC = DAC + IAC** | | | $1,636,856 |
| **Cost Effectiveness ($/ton pollutant Removed)** | | | $10,302 |

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SNCR Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) Cost indices used to adjust 2009 costs to 2011 costs (2009 CI= 109.594, 2011 CI= 113.094)
3) The controlled NOx emissions are adjusted to account for 38 tons of ammonia slip assuming that ammonia emissions are equivalent to NOx emissions on a ton for ton basis.

# Table 2-3a
# SCR COSTING DEVELOPMENT
# FOR CAPITAL AND OPERATION AND MAINTENANCE COSTS

| Variable | Designation | Units | Value | Equation/Input(1) |
|---|---|---|---|---|
| **SCR CAPITAL COST FOR CORETTE - 30 DAY AVERAGE NOx** | | | | |
| Unit Capacity (Gross) | A | (MW) | 162 | Input |
| Retrofit Factor | B | | 2 | Difficulty of Retrofit |
| Gross heat rate | C | Btu/KW-hr | 11,982 | Input |
| NOx Emiss Rate | D | lbs/MMBtu | 0.2 | Uncontrolled |
| $SO_2$ Emiss Rate | E | lbs/MMBtu | 0.6 | Uncontrolled |
| Type of Coal | F | PRB | | Input |
| Coal Factor | G | | 1.05 | Input |
| Heat Rate Factor | H | | 1.1982 | C / 10,000 |
| Heat Input | I | Btu/hr | 1.94E+09 | A X C x 1000 |
| Capacity Factor | J | (%) | 89.0 | Input |
| NOx Removal Eff | K | (%) | 70.00 | Input |
| NOx Removal Factor | L(2) | (lbs/hr) | 0.875 | (Based on Model Plant) |
| NOx Removed | M | (lbs/hr) | 271.75 | $D X I / 10^6 * K / 100$ |
| Urea Rate | N | (lbs/hr) | 189.85 | M x 0.525 * 60/46 *1.01/.99 |
| Steam Required | M | (lbs/hr) | 214.53 | N x 1.13 |
| Urea Cost 50% wgt Soln | R | ($/ton) | 450 | Input |
| Catalyst Cost | S | ($/m3) | 8000 | Input |
| Steam Cost | U | ($/klbs) | 4 | Input |
| Operating Labor Rate | V | ($/hr) | 60 | Input |
| **CAPITAL EQUIPMENT COSTS** | | | | |
| SCR Ducts, Reactor Island | BMR | ($) | $46,687,331 | $180000 \times B X L^{0.2} \times (AxGxH)^{0.92}$ |
| Base Reagent Prep Cost | BMF | ($) | $1,664,665 | $410000 \times M^{0.25}$ |
| ID Fans, Anciliary Equip | BMB | ($) | $7,090,743 | $380000 \times B \times (AxGxH)^{0.42}$ |
| Bare Module Cost | BM | ($) | $55,442,739 | BMR + BMF + BMB |
| Engineering, Const Mgmt | A1 | ($) | $5,544,274 | 10% of BM |
| Labor Adjustment | A2 | ($) | $5,544,274 | 10% of BM |
| Contractor Profit, Fees | A3 | ($) | $5,544,274 | 10% of BM |
| Cap, Eng, Const Cost | CECC | ($) | $72,075,561 | BM + A1 + A2 + A3 |
| Home office Costs | B1 | ($) | $3,603,778 | 5% of CECC |
| Construction Funds | B2 | ($) | $4,540,760 | 6% of CECC+B1 |
| Total Project Cost | TPC | ($) | $80,220,099 | CECC + B1 + B2 |
| Cost per kW | | | 495 | $/kW |
| **OPERATING AND MAINTENANCE COSTS** | | | | |
| Fixed Operator Cost | FOMO | | $62,400 | 2,080 hrs- 1- half time |
| Maintenance Material | FOMM | | $300,000 | Fixed Annual Cost |
| Total Fixed O&M | FOM | | $362,400 | FOMO + FOMM |
| Urea Cost | VOMR | | $42.72 | N X R |
| Steam Cost | VOMM | | $0.86 | O x U |
| Catalyst cost(3) | VOMW | | $0.35 | $/MWhr |

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SCR Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) S&L lists this variable as = to "I x J"; this is the model plant removal efficiency for PRB coal

3) S&L lists this to be a discrete function of A, G, J, K, and S in $/MW-hr

# Table 2-3b
# PPL BART Cost Effectiveness Analysis
# SCR NOx Control
# 162 Megawatt Coal Fired Steam Electric Plant
# Corette - 30 Day Average NOx

| | | |
|---|---|---|
| Maximum Gross Heat Input | MM Btu/hr | 1,941 |
| Design Percent Load | % | 89 |
| Uncontrolled Emissions | lbs/MMBtu | 0.200 |
| ExhaustTemperature, ($^{o}$F) | T | 405 |
| Steam Turbine Power Output (TMW) | MW | 162 |
| Capacity Factor (89%) | hrs | 7,796 |
| Controlled NOx Emissions | lbs/MMBtu | 0.06 |
| Overall NOx Reduction Efficiency, (%) | % | 70.00 |
| Uncontrolled NOx Emissions, (lb/hr) | | 388.2 |
| Uncontrolled NOx Emissions, (tons/yr) | | 1513.3 |
| Controlled NOx Emissions, (ton/yr) | | 454.0 |
| Annual Interest Rate, (%) | | 7 |
| Equipment Life, (yrs) | yr | 20 |
| Capital Recovery Factor, CRF | CRF | 0.0944 |

| Cost Item | Suggested Factor | Unit Cost | Item Cost |
|---|---|---|---|
| IPM Model, August 20, 2010[(1)] | Capital Cost ($/KW) | 495 | $80,220,099 |
| Equipment Cost Total, (EC) | EC (Adjusted by Cost Index Calcs) | (2011 dollars)[(2)] | $82,782,013 |
| **Total Capital Costs, TCC** | | --- | $82,782,013 |
| **Direct Annual Costs, DAC** | | | |
| | Catalyst Cost[(3)] | VOMW | $442,056 |
| | Urea Cost | VOMR | $333,033 |
| | Steam Cost | VOMM | $6,690 |
| | Maintenance Labor | FOMO | $62,400 |
| | Maintenance Materials | FOMM | $300,000 |
| **Total Direct Annual Costs, DAC** | | | $1,144,180 |
| **Indirect Annual Costs** | | | |
| Capital Recovery | CRF*TCC | --- | $7,814,036 |
| **Total Indirect Annual Costs, IAC** | | | $7,814,036 |
| **Total Annual Costs, TAC = DAC + IAC** | | | $8,958,216 |
| **Cost Effectiveness ($/ton pollutant Removed)** | | | $8,457 |

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SCR Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) Cost indices used to adjust 2009 costs to 2011 costs (2009 CI= 109.594, 2011 CI= 113.094)
3) Cost is for replacement and disposal based on S&L cost estimate in $/MW-hr for PRB coal

# Table 2-3c
# SCR COSTING DEVELOPMENT
# FOR CAPITAL AND OPERATION AND MAINTENANCE COSTS

| Variable | Designation | Units | Value | Equation/Input(1) |
|---|---|---|---|---|
| **SCR CAPITAL COST FOR CORETTE - 24 HOUR AVERAGE NOx** | | | | |
| Unit Capacity (Gross) | A | (MW) | 162 | Input |
| Retrofit Factor | B | | 2 | Difficulty of Retrofit |
| Gross heat rate | C | Btu/KW-hr | 11,982 | Input |
| NOx Emiss Rate | D | lbs/MMBtu | 0.26 | Uncontrolled |
| $SO_2$ Emiss Rate | E | lbs/MMBtu | 0.6 | Uncontrolled |
| Type of Coal | F | PRB | | Input |
| Coal Factor | G | | 1.05 | Input |
| Heat Rate Factor | H | | 1.1982 | C / 10,000 |
| Heat Input | I | Btu/hr | 1.94E+09 | A X C x 1000 |
| Capacity Factor | J | (%) | 89.0 | Input |
| NOx Removal Eff | K | (%) | 76.92 | Input |
| NOx Removal Factor | L(2) | (lbs/hr) | 0.875 | (Based on Model Plant) |
| NOx Removed | M | (lbs/hr) | 388.22 | D X I / $10^6$ * K / 100 |
| Urea Rate | N | (lbs/hr) | 271.21 | M x 0.525 * 60/46 *1.01/.99 |
| Steam Required | M | (lbs/hr) | 306.47 | N x 1.13 |
| Urea Cost 50% wgt Soln | R | ($/ton) | 450 | Input |
| Catalyst Cost | S | ($/m3) | 8000 | Input |
| Steam Cost | U | ($/klbs) | 4 | Input |
| Operating Labor Rate | V | ($/hr) | 60 | Input |
| **CAPITAL EQUIPMENT COSTS** | | | | |
| SCR Ducts, Reactor Island | BMR | ($) | $46,687,331 | 180000 x B X $L^{0.2}$ x $(AxGxH)^{0.92}$ |
| Base Reagent Prep Cost | BMF | ($) | $1,819,921 | 410000 x $M^{0.25}$ |
| ID Fans, Anciliary Equip | BMB | ($) | $7,090,743 | 380000 x B x $(AxGxH)^{0.42}$ |
| Bare Module Cost | BM | ($) | $55,597,994 | BMR + BMF + BMB |
| Engineering, Const Mgmt | A1 | ($) | $5,559,799 | 10% of BM |
| Labor Adjustment | A2 | ($) | $5,559,799 | 10% of BM |
| Contractor Profit, Fees | A3 | ($) | $5,559,799 | 10% of BM |
| Cap, Eng, Const Cost | CECC | ($) | $72,277,393 | BM + A1 + A2 + A3 |
| Home office Costs | B1 | ($) | $3,613,870 | 5% of CECC |
| Construction Funds | B2 | ($) | $4,553,476 | 6% of CECC+B1 |
| Total Project Cost | TPC | ($) | $80,444,738 | CECC + B1 + B2 |
| Cost per kW | | | 497 | $/kW |
| **OPERATING AND MAINTENANCE COSTS** | | | | |
| Fixed Operator Cost | FOMO | | $62,400 | 2,080 hrs- 1- half time |
| Maintenance Material | FOMM | | $300,000 | Fixed Annual Cost |
| Total Fixed O&M | FOM | | $362,400 | FOMO + FOMM |
| Urea Cost | VOMR | | $61.02 | N X R |
| Steam Cost | VOMM | | $1.23 | O x U |
| Catalyst cost(3) | VOMW | | $0.35 | $/MWhr |

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SCR Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) S&L lists this variable as = to "I x J"; this is the model plant removal efficiency for PRB coal

3) S&L lists this to be a discrete function of A, G, J, K, and S in $/MW-hr

# Table 2-3d
# PPL BART Cost Effectiveness Analysis
# SCR NOx Control
# 162 Megawatt Coal Fired Steam Electric Plant
# Corette 24 Hour Average NOx

| | | |
|---|---|---|
| Maximum Gross Heat Input | MM Btu/hr | 1,941 |
| Design Percent Load | % | 89 |
| Uncontrolled Emissions | lbs/MMBtu | 0.260 |
| ExhaustTemperature, ($^{o}$F) | T | 405 |
| Steam Turbine Power Output (TMW) | MW | 162 |
| Capacity Factor (89%) | hrs | 7,796 |
| Controlled NOx Emissions | lbs/MMBtu | 0.06 |
| Overall NOx Reduction Efficiency, (%) | % | 76.92 |
| Uncontrolled NOx Emissions, (lb/hr) | | 504.7 |
| Uncontrolled NOx Emissions, (tons/yr) | | 1967.3 |
| Controlled NOx Emissions, (ton/yr) | | 454.0 |
| Annual Interest Rate, (%) | | 7 |
| Equipment Life, (yrs) | yr | 20 |
| Capital Recovery Factor, CRF | CRF | 0.0944 |

| Cost Item | Suggested Factor | Unit Cost | Item Cost |
|---|---|---|---|
| IPM Model, August 20, 2010[1] | Capital Cost ($/KW) | 497 | $80,444,738 |
| Equipment Cost Total, (EC) | EC (Adjusted by Cost Index Calcs) | (2011 dollars)[2] | $82,742,030 |
| **Total Capital Costs, TCC** | | --- | $82,742,030 |
| **Direct Annual Costs, DAC** | | | |
| | Catalyst Cost[3] | VOMW | $442,056 |
| | Urea Cost | VOMR | $475,762 |
| | Steam Cost | VOMM | $9,558 |
| | Maintenance Labor | FOMO | $62,400 |
| | Maintenance Materials | FOMM | $300,000 |
| **Total Direct Annual Costs, DAC** | | | $1,289,776 |
| **Indirect Annual Costs** | | | |
| Capital Recovery | CRF*TCC | --- | $7,810,262 |
| **Total Indirect Annual Costs, IAC** | | | $7,810,262 |
| **Total Annual Costs, TAC = DAC + IAC** | | | $9,100,038 |
| **Cost Effectiveness ($/ton pollutant Removed)** | | | $6,013 |

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SCR Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) Cost indices used to adjust 2009 costs to 2011 costs (2009 CI= 109.594, 2011 CI= 113.094)
3) Cost is for replacement and disposal based on S&L cost estimate in $/MW-hr for PRB coal

# ATTACHMENT A-1

# COMBUSTION CONTROLS COST TABLES

## 5.2 Nitrogen Oxides Control Technology

The EPA Base Case v.4.10 includes two categories of $NO_x$ reduction technologies: combustion and post-combustion controls. Combustion controls reduce $NO_x$ emissions during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Post-combustion controls operate downstream of the combustion process and remove $NO_x$ emissions from the flue gas. All the specific combustion and post-combustion technologies included in EPA Base Case v.4.10 are commercially available and currently in use in numerous power plants.

### 5.2.1 Combustion Controls

The EPA Base Case v.4.10 representation of combustion controls uses equations that are tailored to the boiler type, coal type, and combustion controls already in place and allow appropriate additional combustion controls to be exogenously applied to generating units based on the $NO_x$ emission limits they face. Characterizations of the emission reductions provided by combustion controls are presented in Table 3-1.3 in Appendix 3-1. The EPA Base Case v.4.10 cost assumptions for $NO_x$ Combustion Controls are summarized in Table 5-5. Table 5-6 provides a mapping of existing coal unit configurations and incremental combustion controls applied in EPA Base Case v.4.10 to achieve state-of-the-art combustion control configuration.

**Table 5-5 Cost (2007$) of $NO_x$ Combustion Controls for Coal Boilers (300 MW Size)**

| Boiler Type | Technology | Capital ($/kW) | Fixed O&M ($/kW-yr) | Variable O&M (mills/kWh) |
|---|---|---|---|---|
| Dry Bottom Wall-Fired | Low $NO_x$ Burner without Overfire Air (LNB without OFA) | 45 | 0.3 | 0.07 |
| | Low $NO_x$ Burner with Overfire Air (LNB with OFA) | 61 | 0.4 | 0.09 |
| Tangentially-Fired | Low $NO_x$ Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1) | 24 | 0.2 | 0.00 |
| | Low $NO_x$ Coal-and-Air Nozzles with Separated Overfire Air (LNC2) | 33 | 0.2 | 0.03 |
| | Low $NO_x$ Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3) | 38 | 0.3 | 0.03 |
| Vertically-Fired | $NO_x$ Combustion Control | 29 | 0.2 | 0.06 |

**Scaling Factor**

The following scaling factor is used to obtain the capital and fixed operating and maintenance costs applicable to the capacity (in MW) of the unit taking on combustion controls. No scaling factor is applied in calculating the variable operating and maintenance cost.

LNB without OFA & LNB with OFA = ($ for $X$ MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.359}$

LNC1, LNC2 and LNC3 = ($ for $X$ MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.359}$

Vertically-Fired = ($ for $X$ MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.553}$

where

($ for 300 MW Unit) is the value obtained using the factors shown in the above table and $X$ is the capacity (in MW) of the unit taking on combustion controls.

**Table 5-6 Incremental Combustion $NO_x$ Controls in EPA Base Case v.4.10**

| Boiler Type | Existing $NO_x$ Combustion Control | Incremental Combustional Control |
|---|---|---|
| Cell | LNB | OFA |
| | NGR | LNB AND OFA |
| Cyclone | -- | OFA |
| Stoker/SPR | -- | OFA |
| Tangential | -- | LNC3 |
| | LA | LNC3 |
| | LNB | CONVERSION FROM LNC1 TO LNC3 |
| | LNB + OFA | CONVERSION FROM LNC1 TO LNC3 |
| | LNC1 | CONVERSION FROM LNC1 TO LNC3 |
| | LNC2 | CONVERSION FROM LNC2 TO LNC3 |
| | OFA | LNC1 |
| | ROFA | LNB |
| Vertical | -- | $NO_x$ Combustion Control - Vertically Fired Units |
| Wall | -- | LNB AND OFA |
| | LA | LNB AND OFA |
| | LNB | OFA |
| | LNF | OFA |
| | OFA | LNB |

### 5.2.2 Post-combustion Controls

The EPA Base Case v.4.10 includes two post-combustion retrofit control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Base Case v.4.10 oil/gas steam units are eligible for SCR only. $NO_x$ reduction in an SCR system takes place by injecting ammonia ($NH_3$) vapor into the flue gas stream where the $NO_x$ is reduced to nitrogen (N2) and water $H_2O$ abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten. As its name implies, SNCR operates without a catalyst. In SNCR a nitrogenous reducing agent (reagent), typically ammonia or urea, is injected into, and mixed with, hot flue gas where it reacts with the $NO_x$ in the gas stream reducing it to nitrogen gas and water vapor. Due to the presence of a catalyst, SCR can achieve greater $NO_x$ reductions than SNCR. However, SCR costs are higher.

Table 5-7 summarizes the performance and applicability assumptions in EPA Base Case v.4.10 for each $NO_x$ post-combustion control technology and provides a cross reference to information on cost assumptions.

**Table 5-7 Summary of Retrofit $NO_x$ Emission Control Performance Assumptions**

| Control Performance Assumptions | Selective Catalytic Reduction (SCR) | | Selective Non-Catalytic Reduction (SNCR) |
|---|---|---|---|
| Unit Type | Coal | Oil/Gas | Coal |
| Percent Removal | 90% down to 0.06 lb/MMBtu | 80% | Pulverized Coal: 35%<br>Fluidized Bed: 50% |
| Size Applicability | Units ≥ 25 MW | Units ≥ 25 MW | Units ≥ 25 MW |
| Costs (2007$) | See Table 5-8 | See Table 5-9 | See Table 5-8 |

# ATTACHMENT A-2

# SNCR COST DEVELOPMENT METHODOLOGY – SARGENT & LUNDY, LLC, AUGUST 2010

# IPM Model – Revisions to Cost and Performance for APC Technologies

## SNCR Cost Development Methodology

**FINAL**

August 2010

Project 12301-007

Perrin Quarles Associates, Inc.

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

## LEGAL NOTICE

*This analysis ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the sole use of Perrin Quarles Associates, Inc. ("Client") in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.*

*This work was funded and reviewed by the U.S. Environmental Protection Agency under the supervision of William A. Stevens, Senior Advisor – Power Technologies. Additional input and review was provided by Dr. Jim Staudt, President of Andover Technology Partners.*

# SNCR Cost Development Methodology – Final

## Establishment of Cost Basis

The formulation of the SNCR cost estimating model is based upon a proprietary Sargent & Lundy LLC (S&L) in-house data base of recent (2009) quotes for both lump sum contracts and EPC. The S&L data was analyzed in detail regarding project specifics such as coal type, boiler type, and NOx reduction efficiency. The S&L in-house data includes projects that involved cyclone boilers, T-fired and wall fired systems with multiple levels of injection. The cyclone boiler costs include rich reagent injection (RRI). The data was the basis for the cost estimate formulations developed.

The S&L data was fitted with a least squares curve to establish the trend in $/kW as a function of gross MW. The EPA/IPM SNCR cost model parameters were adjusted to account for market changes and escalation, and then the model output was compared to the S&L data. The EPA/IPM model output followed a $/kW correlation very similar to the S&L in-house data, once the adjustments were made to the model.

The rapid rise in project costs at the lower end of the MW range is due primarily to economies of scale. Additionally, older power plants in the 50 MW range tend to have plant sites that are more compact and therefore difficult to accommodate the reagent storage areas and piping, injection mixing/dilution equipment and construction activities. The smaller power plants also tend to have older control systems which may require upgrades to accommodate the new SNCR control system.

The S&L data includes SNCR projects with various types of boilers, coals, sulfur levels and retrofit complexities. The data represents an average of boiler effects, such as cyclone, wall fired or CFB. The least squares curve fits were based upon the following assumptions:

- Retrofit Factor =1
- Gross Heat Rate = 10,000
- $SO_2$ Rate = < 3 lb/MMBtu
- Type of Coal = PRB
- Project Execution = Multiple lump sum contracts

## Methodology

### Inputs

To predict future retrofit costs several input variables are required. The unit size in MW and NOx levels are the major variables for the capital cost estimation followed by the type of fuel (high sulfur Bituminous). The fuel type affects the air pre-heater costs if sulfuric acid or ammonium bisulfate deposition poses a problem. In general, if the level of $SO_2$ is above 3 lb/MMBtu, it is assumed that air heater modifications will be required. The unit heat rate factors into the amount of NOx generated and ultimately the size of the

SNCR reagent preparation system. A retrofit factor that equates to difficulty in construction of the system must be defined. The $NO_x$ rate and removal efficiency will impact the amount of urea required and size of the reagent handling equipment.

The inputs that impact the variable O&M costs are based primarily on the plant capacity factor and the removal efficiency. The NOx removal efficiency specifically affects the reagent and dilution water costs.

## Outputs

### *Total Project Costs (TPC)*

The base module costs are calculated for each required module (BM). The base module costs include:

- Equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Retrofit factor.

The base module costs do not include:

- Engineering and Construction Management
- Owner's cost; and
- AFUDC.

The base modules are:

BMS = Base module SNCR cost.

BMA = Base module air pre-heater cost.

BMB = Base module balance of plant costs including: piping, electrical, site upgrades, etc…

BM = BMS + BMA + BMB

The total base module cost (BM) is increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

# SNCR Cost Development Methodology – Final

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional expenditures for the project are computed based on the CECC. The additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC.

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the Owner's home office costs. An example of the capital cost estimation is included in Table 1.

***Fixed O&M (FOM)***

The fixed operating and maintenance cost is a function of the additional operations staff (FOMO) and maintenance labor and materials (FOMM) associated with the SNCR installation. The FOM is the sum of the FOMO and the FOMM.

The following factors and assumptions underlie calculations of the FOM:

- In general, 1 additional operator is required for all installations. The FOMO is based on the number of additional operations staff required; and

- The fixed costs for maintenance materials and labor are a direct function of the base module cost (BM) at a retrofit factor of 1.0.

***Variable O&M (VOM)***

Variable O&M is a function of:

- Reagent consumption;
- Dilution water consumption.

All of the VOM costs must be adjusted for the plant capacity factor.

The reagent consumption rate is a function of unit size, $NO_x$ feed rate and removal efficiency. A utilization factor of 15% is used for units with an inlet NOx of 0.3 lb/MMBtu or lower and 25% for units with an inlet NOx greater than 0.3 lb/MMBtu. For CFB boilers a utilization factor of 25% is used. A reagent cost of $620 per ton of 100%

urea is used in the model. The dilution water usage is based upon reagent consumption rate.

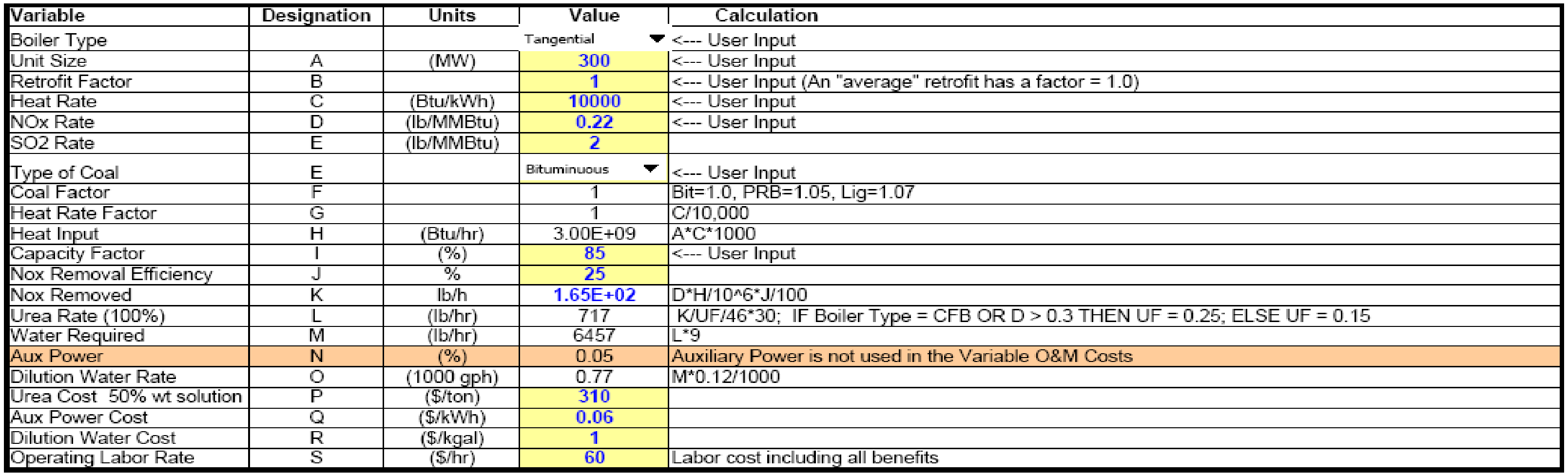
The auxiliary power required for the SNCR system is not included in the VOM. The major systems that impact the power requirements are compressed air or blower requirements for the urea injection system and the reagent supply system.

The variables that contribute to the overall VOM are:

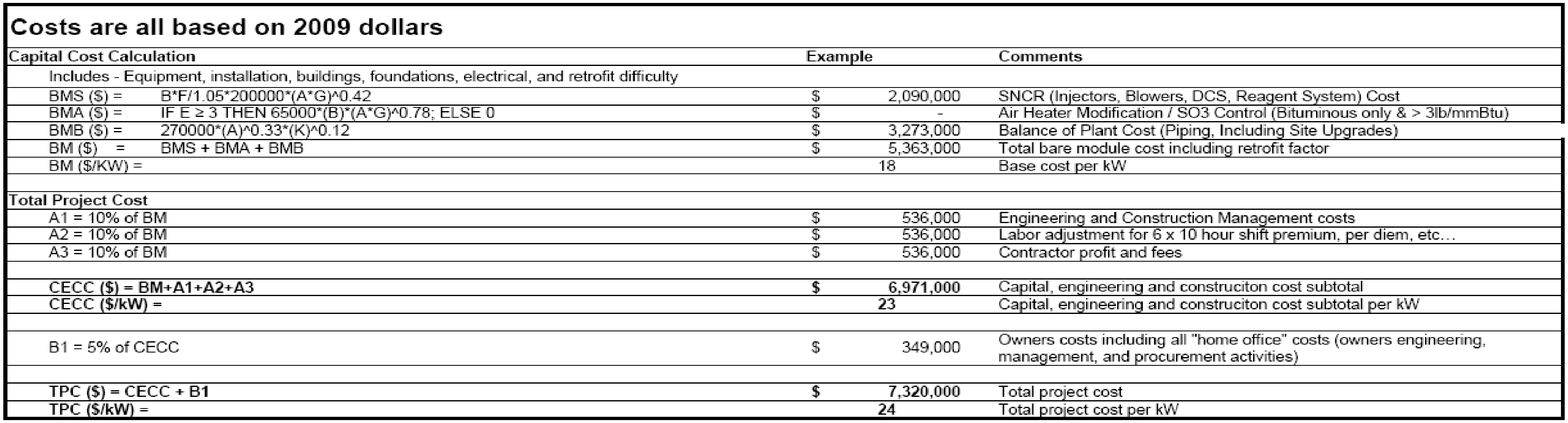
VOMR = Variable O&M costs for urea reagent.
VOMM = Variable O&M costs for dilution water.
VOM = VOMR + VOMM.

# SNCR Cost Development Methodology – Final

**Table 1. Example of the Capital Cost Estimate Work Sheet (for T-fired boilers).**



| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Boiler Type | | | Tangential ▼ | <--- User Input |
| Unit Size | A | (MW) | 300 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Heat Rate | C | (Btu/kWh) | 10000 | <--- User Input |
| NOx Rate | D | (lb/MMBtu) | 0.22 | <--- User Input |
| SO2 Rate | E | (lb/MMBtu) | 2 | |
| Type of Coal | E | | Bituminuous ▼ | <--- User Input |
| Coal Factor | F | | 1 | Bit=1.0, PRB=1.05, Lig=1.07 |
| Heat Rate Factor | G | | 1 | C/10,000 |
| Heat Input | H | (Btu/hr) | 3.00E+09 | A*C*1000 |
| Capacity Factor | I | (%) | 85 | <--- User Input |
| Nox Removal Efficiency | J | % | 25 | |
| Nox Removed | K | lb/h | 1.65E+02 | D*H/10^6*J/100 |
| Urea Rate (100%) | L | (lb/hr) | 717 | K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15 |
| Water Required | M | (lb/hr) | 6457 | L*9 |
| Aux Power | N | (%) | 0.05 | Auxiliary Power is not used in the Variable O&M Costs |
| Dilution Water Rate | O | (1000 gph) | 0.77 | M*0.12/1000 |
| Urea Cost 50% wt solution | P | ($/ton) | 310 | |
| Aux Power Cost | Q | ($/kWh) | 0.06 | |
| Dilution Water Cost | R | ($/kgal) | 1 | |
| Operating Labor Rate | S | ($/hr) | 60 | Labor cost including all benefits |

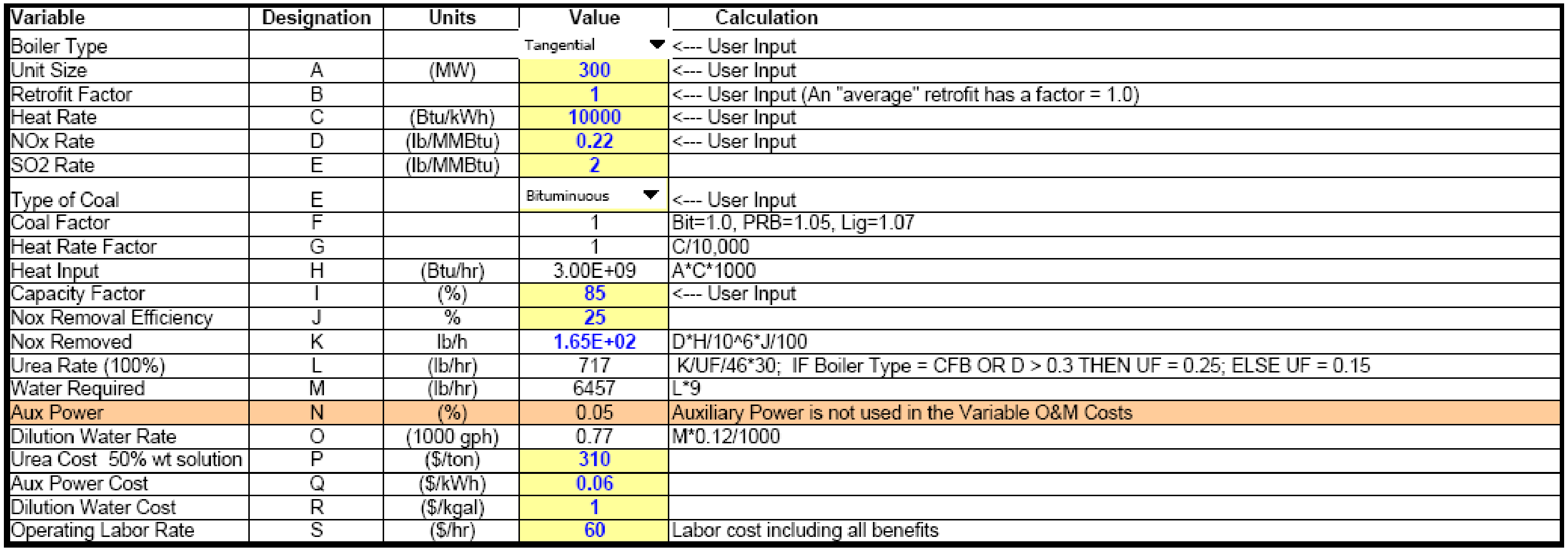


**Costs are all based on 2009 dollars**

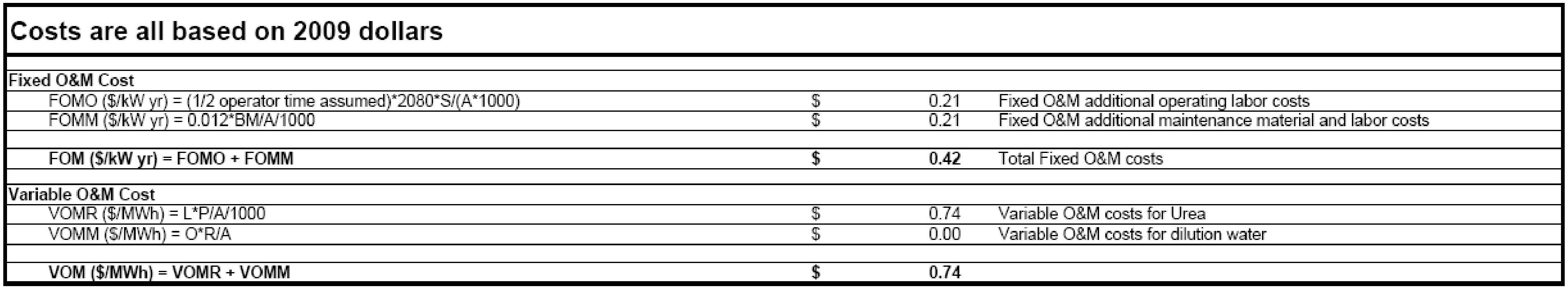
| Capital Cost Calculation | | Example | | Comments |
|---|---|---|---|---|
| Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty | | | | |
| BMS ($) = | B*F/1.05*200000*(A*G)^0.42 | $ | 2,090,000 | SNCR (Injectors, Blowers, DCS, Reagent System) Cost |
| BMA ($) = | IF E ≥ 3 THEN 65000*(B)*(A*G)^0.78; ELSE 0 | $ | - | Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu) |
| BMB ($) = | 270000*(A)^0.33*(K)^0.12 | $ | 3,273,000 | Balance of Plant Cost (Piping, Including Site Upgrades) |
| BM ($) = | BMS + BMA + BMB | $ | 5,363,000 | Total bare module cost including retrofit factor |
| BM ($/KW) = | | 18 | | Base cost per kW |
| | | | | |
| **Total Project Cost** | | | | |
| A1 = 10% of BM | | $ | 536,000 | Engineering and Construction Management costs |
| A2 = 10% of BM | | $ | 536,000 | Labor adjustment for 6 x 10 hour shift premium, per diem, etc… |
| A3 = 10% of BM | | $ | 536,000 | Contractor profit and fees |
| | | | | |
| **CECC ($) = BM+A1+A2+A3** | | **$** | **6,971,000** | Capital, engineering and construciton cost subtotal |
| **CECC ($/kW) =** | | **23** | | Capital, engineering and construciton cost subtotal per kW |
| | | | | |
| B1 = 5% of CECC | | $ | 349,000 | Owners costs including all "home office" costs (owners engineering, management, and procurement activities) |
| | | | | |
| **TPC ($) = CECC + B1** | | **$** | **7,320,000** | Total project cost |
| **TPC ($/kW) =** | | **24** | | Total project cost per kW |

## SNCR Cost Development Methodology – Final

### Table 2. Example of the Fixed and Variable O&M Cost Estimate Work Sheet (for T-fired boilers).



| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Boiler Type | | | Tangential ▼ | <--- User Input |
| Unit Size | A | (MW) | 300 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Heat Rate | C | (Btu/kWh) | 10000 | <--- User Input |
| NOx Rate | D | (lb/MMBtu) | 0.22 | <--- User Input |
| SO2 Rate | E | (lb/MMBtu) | 2 | |
| Type of Coal | E | | Bituminuous ▼ | <--- User Input |
| Coal Factor | F | | 1 | Bit=1.0, PRB=1.05, Lig=1.07 |
| Heat Rate Factor | G | | 1 | C/10,000 |
| Heat Input | H | (Btu/hr) | 3.00E+09 | A*C*1000 |
| Capacity Factor | I | (%) | 85 | <--- User Input |
| Nox Removal Efficiency | J | % | 25 | |
| Nox Removed | K | lb/h | 1.65E+02 | D*H/10^6*J/100 |
| Urea Rate (100%) | L | (lb/hr) | 717 | K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15 |
| Water Required | M | (lb/hr) | 6457 | L*9 |
| Aux Power | N | (%) | 0.05 | Auxiliary Power is not used in the Variable O&M Costs |
| Dilution Water Rate | O | (1000 gph) | 0.77 | M*0.12/1000 |
| Urea Cost 50% wt solution | P | ($/ton) | 310 | |
| Aux Power Cost | Q | ($/kWh) | 0.06 | |
| Dilution Water Cost | R | ($/kgal) | 1 | |
| Operating Labor Rate | S | ($/hr) | 60 | Labor cost including all benefits |



**Costs are all based on 2009 dollars**

| | | | |
|---|---|---|---|
| Fixed O&M Cost | | | |
| FOMO ($/kW yr) = (1/2 operator time assumed)*2080*S/(A*1000) | $ | 0.21 | Fixed O&M additional operating labor costs |
| FOMM ($/kW yr) = 0.012*BM/A/1000 | $ | 0.21 | Fixed O&M additional maintenance material and labor costs |
| | | | |
| **FOM ($/kW yr) = FOMO + FOMM** | **$** | **0.42** | Total Fixed O&M costs |
| | | | |
| Variable O&M Cost | | | |
| VOMR ($/MWh) = L*P/A/1000 | $ | 0.74 | Variable O&M costs for Urea |
| VOMM ($/MWh) = O*R/A | $ | 0.00 | Variable O&M costs for dilution water |
| | | | |
| **VOM ($/MWh) = VOMR + VOMM** | **$** | **0.74** | |

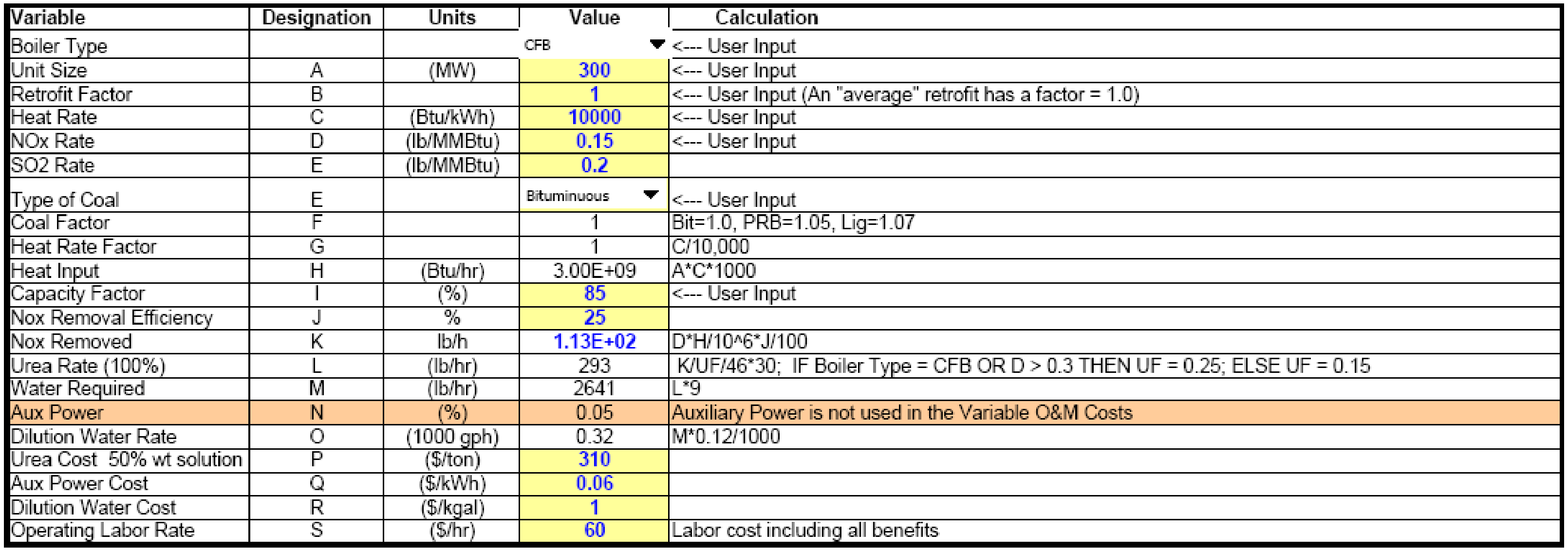
### Table 3. Example of the Capital Cost Estimate Work Sheet (for CFB boilers).

| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Boiler Type | | | CFB ▼ | <--- User Input |
| Unit Size | A | (MW) | 300 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Heat Rate | C | (Btu/kWh) | 10000 | <--- User Input |
| NOx Rate | D | (lb/MMBtu) | 0.15 | <--- User Input |
| SO2 Rate | E | (lb/MMBtu) | 0.2 | |
| Type of Coal | E | | Bituminuous ▼ | <--- User Input |
| Coal Factor | F | | 1 | Bit=1.0, PRB=1.05, Lig=1.07 |
| Heat Rate Factor | G | | 1 | C/10,000 |
| Heat Input | H | (Btu/hr) | 3.00E+09 | A*C*1000 |
| Capacity Factor | I | (%) | 85 | <--- User Input |
| Nox Removal Efficiency | J | % | 25 | |
| Nox Removed | K | lb/h | 1.13E+02 | D*H/10^6*J/100 |
| Urea Rate (100%) | L | (lb/hr) | 293 | K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15 |
| Water Required | M | (lb/hr) | 2641 | L*9 |
| Aux Power | N | (%) | 0.05 | Auxiliary Power is not used in the Variable O&M Costs |
| Dilution Water Rate | O | (1000 gph) | 0.32 | M*0.12/1000 |
| Urea Cost 50% wt solution | P | ($/ton) | 310 | |
| Aux Power Cost | Q | ($/kWh) | 0.06 | |
| Dilution Water Cost | R | ($/kgal) | 1 | |
| Operating Labor Rate | S | ($/hr) | 60 | Labor cost including all benefits |

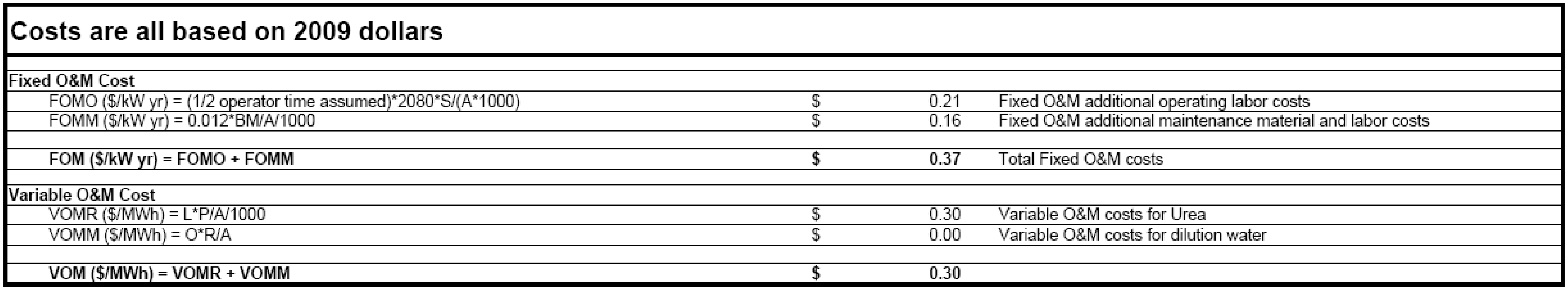
**Costs are all based on 2009 dollars**

| Capital Cost Calculation | Example | Comments |
|---|---|---|
| Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty | | |
| BMS ($) = B*F/1.05*200000*(A*G)^0.42 | $ 1,568,000 | SNCR (Injectors, Blowers, DCS, Reagent System) Cost |
| BMA ($) = IF E ≥ 3 THEN 65000*(B)*(A*G)^0.78; ELSE 0 | $ - | Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu) |
| BMB ($) = 270000*(A)^0.33*(K)^0.12 | $ 2,344,000 | Balance of Plant Cost (Piping, Including Site Upgrades) |
| BM ($) = BMS + BMA + BMB | $ 3,912,000 | Total bare module cost including retrofit factor |
| BM ($/KW) = | 13 | Base cost per kW |
| | | |
| **Total Project Cost** | | |
| A1 = 10% of BM | $ 391,000 | Engineering and Construction Management costs |
| A2 = 10% of BM | $ 391,000 | Labor adjustment for 6 x 10 hour shift premium, per diem, etc... |
| A3 = 10% of BM | $ 391,000 | Contractor profit and fees |
| | | |
| **CECC ($) = BM+A1+A2+A3** | **$ 5,085,000** | Capital, engineering and construciton cost subtotal |
| **CECC ($/kW) =** | **17** | Capital, engineering and construciton cost subtotal per kW |
| | | |
| B1 = 5% of CECC | $ 254,000 | Owners costs including all "home office" costs (owners engineering, management, and procurement activities) |
| | | |
| **TPC ($) = CECC + B1** | **$ 5,339,000** | Total project cost |
| **TPC ($/kW) =** | **18** | Total project cost per kW |

**Table 4. Example of the Fixed and Variable O&M Cost Estimate Work Sheet (for CFB boilers).**



| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Boiler Type | | | CFB | <--- User Input |
| Unit Size | A | (MW) | 300 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Heat Rate | C | (Btu/kWh) | 10000 | <--- User Input |
| NOx Rate | D | (lb/MMBtu) | 0.15 | <--- User Input |
| SO2 Rate | E | (lb/MMBtu) | 0.2 | |
| Type of Coal | E | | Bituminuous | <--- User Input |
| Coal Factor | F | | 1 | Bit=1.0, PRB=1.05, Lig=1.07 |
| Heat Rate Factor | G | | 1 | C/10,000 |
| Heat Input | H | (Btu/hr) | 3.00E+09 | A*C*1000 |
| Capacity Factor | I | (%) | 85 | <--- User Input |
| Nox Removal Efficiency | J | % | 25 | |
| Nox Removed | K | lb/h | 1.13E+02 | D*H/10^6*J/100 |
| Urea Rate (100%) | L | (lb/hr) | 293 | K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15 |
| Water Required | M | (lb/hr) | 2641 | L*9 |
| Aux Power | N | (%) | 0.05 | Auxiliary Power is not used in the Variable O&M Costs |
| Dilution Water Rate | O | (1000 gph) | 0.32 | M*0.12/1000 |
| Urea Cost 50% wt solution | P | ($/ton) | 310 | |
| Aux Power Cost | Q | ($/kWh) | 0.06 | |
| Dilution Water Cost | R | ($/kgal) | 1 | |
| Operating Labor Rate | S | ($/hr) | 60 | Labor cost including all benefits |



**Costs are all based on 2009 dollars**

| | | | |
|---|---|---|---|
| **Fixed O&M Cost** | | | |
| FOMO ($/kW yr) = (1/2 operator time assumed)*2080*S/(A*1000) | $ | 0.21 | Fixed O&M additional operating labor costs |
| FOMM ($/kW yr) = 0.012*BM/A/1000 | $ | 0.16 | Fixed O&M additional maintenance material and labor costs |
| | | | |
| **FOM ($/kW yr) = FOMO + FOMM** | **$** | **0.37** | Total Fixed O&M costs |
| | | | |
| **Variable O&M Cost** | | | |
| VOMR ($/MWh) = L*P/A/1000 | $ | 0.30 | Variable O&M costs for Urea |
| VOMM ($/MWh) = O*R/A | $ | 0.00 | Variable O&M costs for dilution water |
| | | | |
| **VOM ($/MWh) = VOMR + VOMM** | **$** | **0.30** | |

# ATTACHMENT A-3

# SCR COST DEVELOPMENT METHODOLOGY –

# SARGENT & LUNDY, LLC, AUGUST 2010

# IPM Model – Revisions to Cost and Performance for APC Technologies

# SCR Cost Development Methodology

**FINAL**

August 2010

Project 12301-007

Perrin Quarles Associates, Inc.

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

## LEGAL NOTICE

*This analysis ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the sole use of Perrin Quarles Associates, Inc. ("Client") in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.*

*This work was funded and reviewed by the U.S. Environmental Protection Agency under the supervision of William A. Stevens, Senior Advisor – Power Technologies. Additional input and review was provided by Dr. Jim Staudt, President of Andover Technology Partners.*

# SCR Cost Development Methodology – Final

## Establishment of Cost Basis

The formulation of the SCR cost estimating model is based upon two data bases of actual SCR projects. The data bases used were those of the 2004 to 2006 industry cost estimates for SCR units published in the "ANALYSIS OF MOG AND LADCO'S FGD AND SCR CAPACITY AND COST ASSUMPTIONS IN THE EVALUATION OF PROPOSED EGU 1 AND EGU 2 EMISSION CONTROLS" report prepared for Midwest Ozone Group (MOG) and a Sargent & Lundy LLC (S&L) proprietary in-house database. The available data was analyzed in detail regarding project specifics such as coal type, NOx reduction efficiency and air pre-heater requirements, and updated to include the cost of SCR projects available with both data sets.

The data sets were escalated to update the MOG information to 2009 and all of the data was cross referenced with current 2009 projects. The MOG and S&L cost data were updated to reflect the changes in equipment and labor rates. The CEPCI index for power plants was used to escalate the costs. The Handy-Witman index was also used to escalate the project costs to account for regional effects; the results were compared with the CEPCI index and were within 2% for total project costs.

The comparison between the two sets of data was refined by fitting each data set with a least squares curve to obtain an average $/kW project cost as a function of unit size. The data set was then collectively used to generate an average least-squares curve fit. The curve fit indicated that both sets of data produced similar average costs (within 4%) at the 200 MW range, but deviate as the unit size increases to approximately 11% at 600 MW and 13% at 900MW. The costs for retrofitting a plant smaller than 100 MW increase rapidly due to the economy of size. The older units which comprise a large proportion of the plants in this range generally have more compact sites with very short flue gas ducts running from the boiler house to the chimney. Because of the limited space, the SCR reactor and new duct work can be expensive to design and install. Additionally, the plants might not have enough margins in the fans to overcome the pressure drop due to the duct work configuration and SCR reactor and therefore new fans may be required.

The least squares curve fit was based upon an average of the SCR retrofit projects. Retrofit difficulties associated with an SCR may result in capital cost increases of 30 to 50% over the base model. The least squares curve fits were based upon the following assumptions:

- Retrofit Factor =1
- Gross Heat Rate = 9880
- $SO_2$ Rate = < 3 lb/MMBtu
- Type of Coal = Bituminous
- Project Execution = Multiple lump sum contracts

# SCR Cost Development Methodology – Final

## Methodology

### Inputs

To predict future SCR retrofit costs several input variables are required. The unit size in MW is the major variable for the capital cost estimation followed by the type of fuel (Bituminous, PRB, or Lignite) which will influence the flue gas quantities as a result of the moisture content. The fuel type also affects the air pre-heater costs if ammonium bisulfate or sulfuric acid deposition poses a problem. The unit heat rate factors into the amount of flue gas generated and ultimately the size of the SCR reactor and reagent preparation. A retrofit factor that equates to difficulty in construction of the system must be defined. The $NO_x$ rate and removal efficiency will impact the amount of catalyst required and size of the reagent handling equipment. The elevation of the site must be considered separately and factored into the unit MW size accordingly due to its effects on the flue gas volume.

The inputs that impact the variable O&M costs are based primarily on the plant capacity factor and the removal efficiency. The NOx removal efficiency specifically affects the SCR catalyst, reagent and steam costs. The lower level of NOx removal is recommended as:

- 0.07 NOx lb/mmBtu – Bituminous
- 0.05 NOx lb/mmBtu – PRB
- 0.05 NOx lb/mmBtu – Lignite

### Outputs

#### *Total Project Costs (TPC)*

First the bare costs are calculated for each required module (BM). The bare module costs include:

- Equipment
- Installation
- Buildings
- Foundations
- Electrical
- Retrofit factor

The bare module costs do not include:

- Engineering and Construction Management
- Owner's cost
- AFUDC

The modules are:

BMR = Base module SCR cost
BMF = Base module reagent preparation cost
BMA = Base module air pre-heater cost
BMB = Base module balance of plan costs including: ID or booster fans, piping, etc…
BM = BMR + BMF + BMA + BMB

The total bare module cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost.
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the BM cost.
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 6% of the CECC and owner's costs. The AFUDC is based on a two-year engineering and construction cycle.

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures. Table 1 contains an example of the capital cost estimation.

### *Fixed O&M (FOM)*

The fixed operating and maintenance cost is a function of the additional operations staff (FOMO) and maintenance labor and materials (FOMM) associated with the SCR installation. The FOM is the sum of the FOMO and the FOMM.

## SCR Cost Development Methodology – Final

In general, 1 additional operator is required for all installations. The FOMO is based on the number of additional operations staff required.

The fixed maintenance materials and labor is a direct function of the bare module cost (BM) at a retrofit factor of 1.0.

### *Variable O&M (VOM)*

Variable O&M is a function of catalyst required and disposal costs, reagent consumption, and steam consumption. All of the VOM costs must be adjusted for plant capacity factor.

The reagent consumption rate is a function of unit size, $NO_x$ feed rate and removal efficiency. The steam usage is based upon reagent consumption rate.

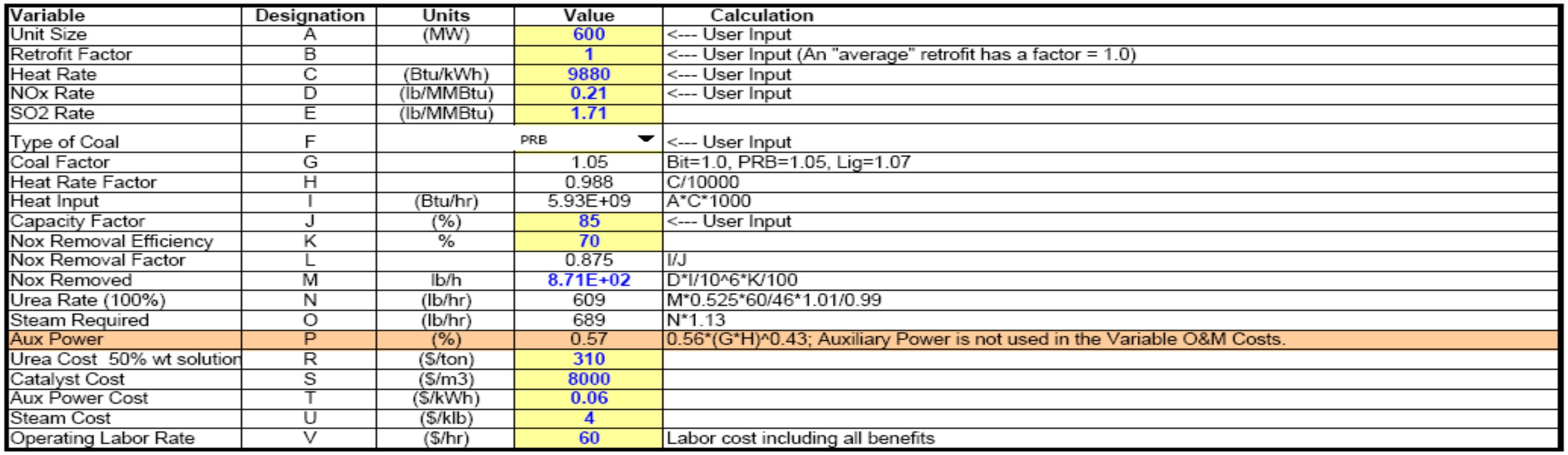
The power required for the SCR system was not included in the variable O&M costs. The power requirements include increased fan power to overcome the added pressure drop across the catalyst and ductwork and the reagent supply system.

The variables that contribute to the overall VOM are:

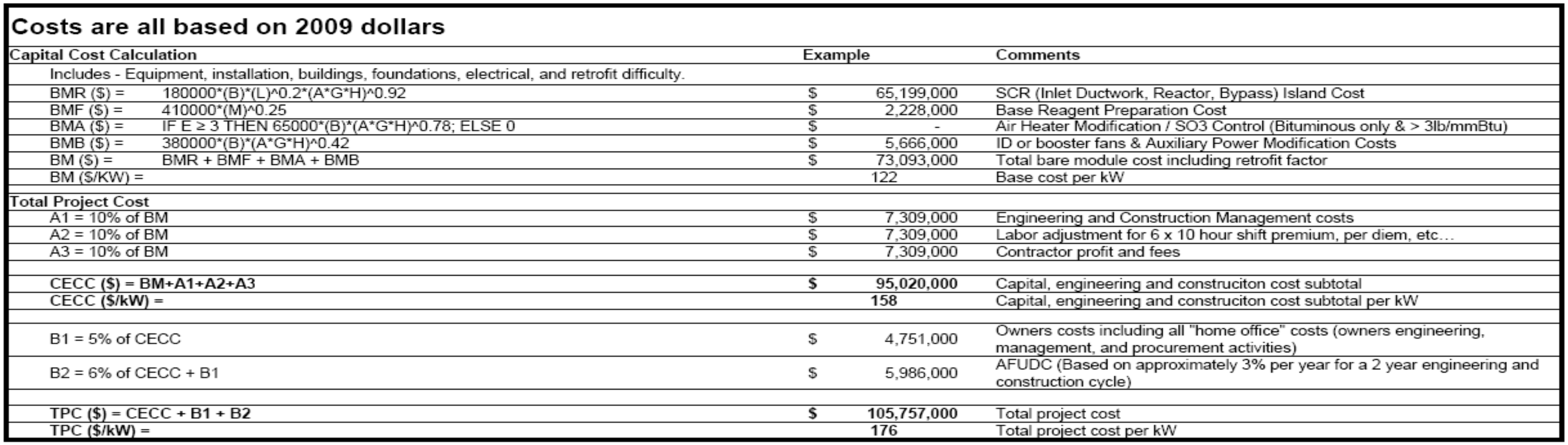
VOMR = Variable O&M costs for urea reagent
VOMW = Variable O&M costs for catalyst replacement & disposal
VOMM = Variable O&M costs for steam

VOM = VOMR + VOMW + VOMM.

## Table 1. Example of the Capital Cost Estimate Work Sheet.



| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Unit Size | A | (MW) | 600 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Heat Rate | C | (Btu/kWh) | 9880 | <--- User Input |
| NOx Rate | D | (lb/MMBtu) | 0.21 | <--- User Input |
| SO2 Rate | E | (lb/MMBtu) | 1.71 | |
| Type of Coal | F | | PRB | <--- User Input |
| Coal Factor | G | | 1.05 | Bit=1.0, PRB=1.05, Lig=1.07 |
| Heat Rate Factor | H | | 0.988 | C/10000 |
| Heat Input | I | (Btu/hr) | 5.93E+09 | A*C*1000 |
| Capacity Factor | J | (%) | 85 | <--- User Input |
| Nox Removal Efficiency | K | % | 70 | |
| Nox Removal Factor | L | | 0.875 | I/J |
| Nox Removed | M | lb/h | 8.71E+02 | D*I/10^6*K/100 |
| Urea Rate (100%) | N | (lb/hr) | 609 | M*0.525*60/46*1.01/0.99 |
| Steam Required | O | (lb/hr) | 689 | N*1.13 |
| Aux Power | P | (%) | 0.57 | 0.56*(G*H)^0.43; Auxiliary Power is not used in the Variable O&M Costs. |
| Urea Cost 50% wt solution | R | ($/ton) | 310 | |
| Catalyst Cost | S | ($/m3) | 8000 | |
| Aux Power Cost | T | ($/kWh) | 0.06 | |
| Steam Cost | U | ($/klb) | 4 | |
| Operating Labor Rate | V | ($/hr) | 60 | Labor cost including all benefits |

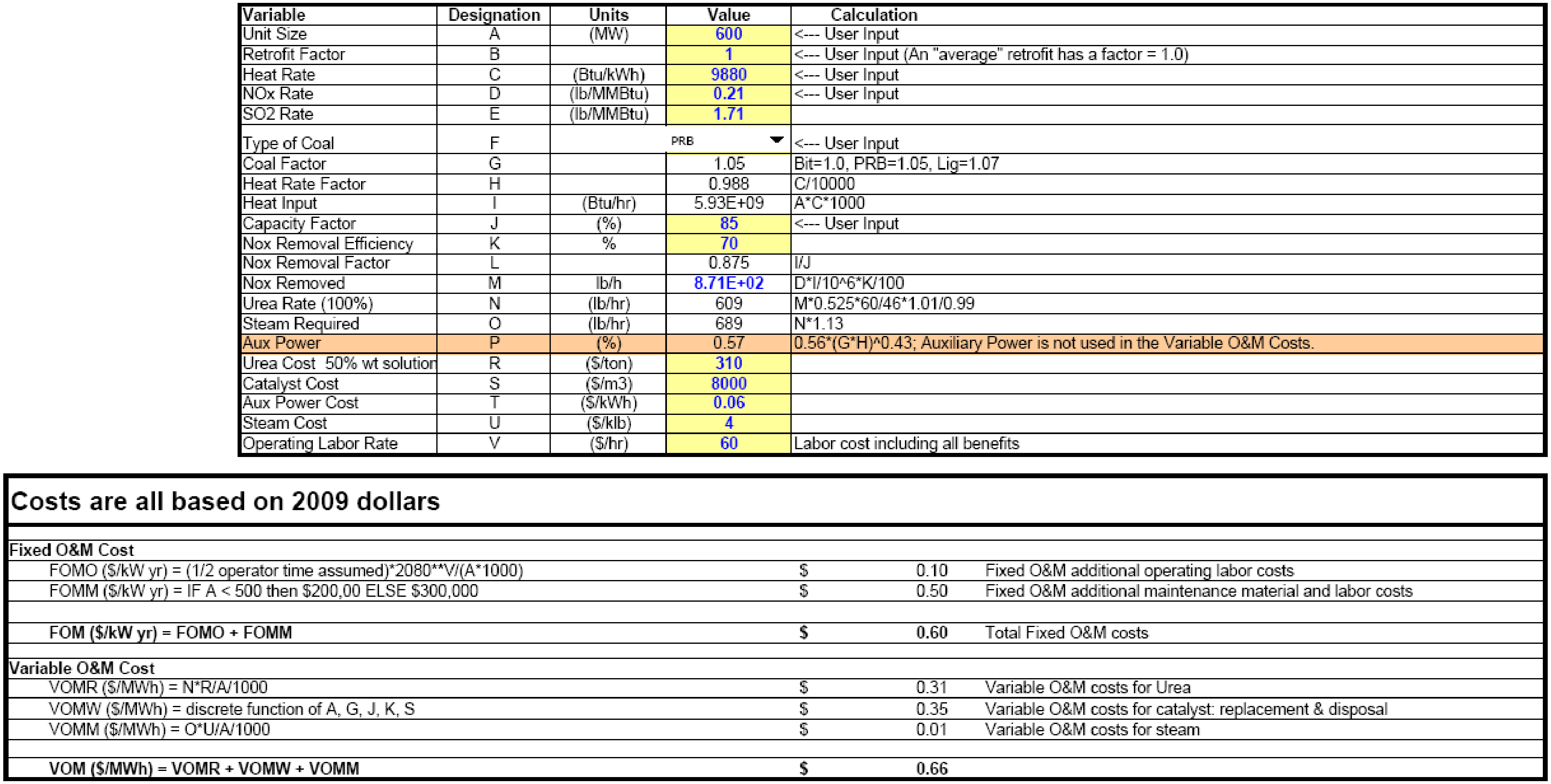


**Costs are all based on 2009 dollars**

| Capital Cost Calculation | | Example | Comments |
|---|---|---|---|
| Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty. | | | |
| BMR ($) = | 180000*(B)*(L)^0.2*(A*G*H)^0.92 | $ 65,199,000 | SCR (Inlet Ductwork, Reactor, Bypass) Island Cost |
| BMF ($) = | 410000*(M)^0.25 | $ 2,228,000 | Base Reagent Preparation Cost |
| BMA ($) = | IF E ≥ 3 THEN 65000*(B)*(A*G*H)^0.78; ELSE 0 | $ - | Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu) |
| BMB ($) = | 380000*(B)*(A*G*H)^0.42 | $ 5,666,000 | ID or booster fans & Auxiliary Power Modification Costs |
| BM ($) = | BMR + BMF + BMA + BMB | $ 73,093,000 | Total bare module cost including retrofit factor |
| BM ($/KW) = | | 122 | Base cost per kW |
| Total Project Cost | | | |
| A1 = 10% of BM | | $ 7,309,000 | Engineering and Construction Management costs |
| A2 = 10% of BM | | $ 7,309,000 | Labor adjustment for 6 x 10 hour shift premium, per diem, etc… |
| A3 = 10% of BM | | $ 7,309,000 | Contractor profit and fees |
| | | | |
| **CECC ($) = BM+A1+A2+A3** | | **$ 95,020,000** | Capital, engineering and construciton cost subtotal |
| **CECC ($/kW) =** | | **158** | Capital, engineering and construciton cost subtotal per kW |
| | | | |
| B1 = 5% of CECC | | $ 4,751,000 | Owners costs including all "home office" costs (owners engineering, management, and procurement activities) |
| B2 = 6% of CECC + B1 | | $ 5,986,000 | AFUDC (Based on approximately 3% per year for a 2 year engineering and construction cycle) |
| | | | |
| **TPC ($) = CECC + B1 + B2** | | **$ 105,757,000** | Total project cost |
| **TPC ($/kW) =** | | **176** | Total project cost per kW |

## SCR Cost Development Methodology – Final

### Table 2. Example of the Fixed and Variable O&M Estimate Work Sheet.



| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Unit Size | A | (MW) | 600 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Heat Rate | C | (Btu/kWh) | 9880 | <--- User Input |
| NOx Rate | D | (lb/MMBtu) | 0.21 | <--- User Input |
| SO2 Rate | E | (lb/MMBtu) | 1.71 | |
| Type of Coal | F | | PRB ▼ | <--- User Input |
| Coal Factor | G | | 1.05 | Bit=1.0, PRB=1.05, Lig=1.07 |
| Heat Rate Factor | H | | 0.988 | C/10000 |
| Heat Input | I | (Btu/hr) | 5.93E+09 | A*C*1000 |
| Capacity Factor | J | (%) | 85 | <--- User Input |
| Nox Removal Efficiency | K | % | 70 | |
| Nox Removal Factor | L | | 0.875 | I/J |
| Nox Removed | M | lb/h | 8.71E+02 | D*I/10^6*K/100 |
| Urea Rate (100%) | N | (lb/hr) | 609 | M*0.525*60/46*1.01/0.99 |
| Steam Required | O | (lb/hr) | 689 | N*1.13 |
| Aux Power | P | (%) | 0.57 | 0.56*(G*H)^0.43; Auxiliary Power is not used in the Variable O&M Costs. |
| Urea Cost 50% wt solution | R | ($/ton) | 310 | |
| Catalyst Cost | S | ($/m3) | 8000 | |
| Aux Power Cost | T | ($/kWh) | 0.06 | |
| Steam Cost | U | ($/klb) | 4 | |
| Operating Labor Rate | V | ($/hr) | 60 | Labor cost including all benefits |

**Costs are all based on 2009 dollars**

| | | | |
|---|---|---|---|
| **Fixed O&M Cost** | | | |
| FOMO ($/kW yr) = (1/2 operator time assumed)*2080**V/(A*1000) | $ | 0.10 | Fixed O&M additional operating labor costs |
| FOMM ($/kW yr) = IF A < 500 then $200,00 ELSE $300,000 | $ | 0.50 | Fixed O&M additional maintenance material and labor costs |
| | | | |
| **FOM ($/kW yr) = FOMO + FOMM** | **$** | **0.60** | Total Fixed O&M costs |
| | | | |
| **Variable O&M Cost** | | | |
| VOMR ($/MWh) = N*R/A/1000 | $ | 0.31 | Variable O&M costs for Urea |
| VOMW ($/MWh) = discrete function of A, G, J, K, S | $ | 0.35 | Variable O&M costs for catalyst: replacement & disposal |
| VOMM ($/MWh) = O*U/A/1000 | $ | 0.01 | Variable O&M costs for steam |
| | | | |
| **VOM ($/MWh) = VOMR + VOMW + VOMM** | **$** | **0.66** | |