

NO_x Control Supplement to Attachment 2 of January 31, 2011 Response To Request for Reasonable Progress Information – Colstrip Generating Plant Units 3&4

Executive Summary

EPA Region 8 has requested additional information to supplement already submitted Reasonable Progress information for Colstrip Generating Plant Units 3&4. This current submittal is in response to USEPA Region 8's May 18, 2011 follow-up letter (in which the Agency clarified its November 5, 2010 request). PPL Montana responded to EPA's November 5, 2010 request on January 31, 2011, and that response provided details of a Best Available Retrofit Technology (BART) analysis performed by PPL to satisfy a PSD permit condition to install BART for NO_x on Colstrip Units 3&4. The response included a description of the low-NO_x concentric firing system (LNCFS) Level III with Separated Overfire Air (SOFA) NO_x control system and the Digital Process Control System (DPCS). These controls were installed under a Consent Decree and were installed and in operation by June 15, 2007 for Unit 3 and by May 9, 2009 for Unit 4. Since the BART approved controls were installed and fully operational, annual NO_x emissions have been reduced by over 14,000 tons per year (approximately a 60% reduction from previous levels).

This addendum to the January 31, 2011 report provides an analysis of postcombustion NO_x controls for Units 3&4 at Colstrip. While the controls installed and in operation have reduced the NO_x emissions to 0.17 lbs/MMBtu, (see EPA CAMD¹ website and the PPL Montana January 31, 2011 submittal), the previous analysis did not include an analysis of the cost-effectiveness of post combustion NO_x controls. The Integrated Planning Model (the IPM)² used by EPA to analyze the national fleet of coal fired boilers includes the post-combustion controls known as Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR), and therefore analysis of the application of these post combustion technologies to Units 3&4 is being submitted to provide a complete review of add-on control technologies. 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

¹ - Environmental Protection Agency's Clean Air Markets Division

² - Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model (see URL)

earlier cost analysis methods. Documentation for and a description of the planning model and control technology cost calculation methodology are found at the following hyperlink:

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

The details of the cost effectiveness calculations for each control technology are provided in Section 2 and the associated tables. A summary is discussed below.

Selective Non-Catalytic Reduction (SNCR) of NO_x 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. It is expected that a 10% incremental reduction of NO_x would be attainable with the addition of SNCR to the Colstrip Units 3&4 resulting in an estimated emission rate of 0.15 lbs/MMBtu. While an estimated additional 502 tons per year of NO_x from each unit would be reduced over the combustion controls and digital process controls already in place, an estimated ammonia slip of 148 tons per year per unit would enter the PM/ SO_2 scrubbers, cause unknown effects on the reaction chemistry and largely be emitted from the stacks. 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 Colstrip Units 3&4 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 effectiveness of this technology by approximately \$3,300/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 significantly higher capital cost and have comparatively lower ammonia slip. In the case of application of SCR to Units 3&4, the NO_x controls would be before the wet scrubbing equipment for PM and SO_2 . The addition of SCR technology to Colstrip Units 3&4 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 control technology would have significant impacts at the plant. The estimated ammonia slip likely would react with components of the exhaust to cause unknown effects on scrubber reaction chemistry and plume opacity issues as well as fine particulate issues due to reactions with other residuals in the scrubber exhaust. Furthermore, there would be impacts due to the limited available space, which is already occupied with the SO_2 wet scrubbing equipment. Reagent preparation equipment, reagent receipt, loading and unloading equipment, and the reactors for SCR would present significant construction and operational difficulties.

The results of this evaluation shows that the cost effectiveness of SNCR is approximately \$10,336 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 effectiveness of SNCR technology by approximately \$3,300/ton.

The estimated cost effectiveness for the addition of SCR to Units 3&4 is approximately \$9,279/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 effectiveness by approximately \$300/ton.³

The high cost per ton of additional NO_x removal with these technologies leads PPL Montana to the conclusion that they are not appropriate technologies for retrofit application to Colstrip Units 3&4. In addition, we believe that no significant visibility benefit is expected from the emission reductions that these technologies would achieve.

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. Units 3&4 are not BART eligible sources and were not part of those previous submittals. 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

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

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

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.

The IPM includes cost estimating methodology for the various low-NO_x burner and overfire air combustion control options. For tangentially fired boilers such as those at Colstrip, cost estimation methods and empirical equations for low NO_x coal-and-air nozzles with close coupled and separated overfire air are also included. Colstrip already has this technology in place as described in PPL Montana's January 31, 2011 response letter. No additional cost analysis of these systems is required.

Historical NO_x emissions for Units 3&4 are shown in the table below⁵. The units' emissions are controlled to target the permit limit⁶ of 0.18 #/MMBtu, 30-day rolling average. Achieving this limit results in nominal estimated control efficiency achieved by the low NO_x equipment and digital controls is 81%⁷. In 2010, the first year with full implementation on both units, the NO_x control equipment installed on Units 3&4 achieved over a 14,000 ton reduction from 2006, the last year prior to installation of these BART level controls. Subsequent years' reductions are expected to consistently remain near this level⁸.

In view of the NO_x reductions experienced at both units last year and the permit limits on the units that require the use of the advanced burner design and digital process control system, the baseline, pre-add-on control, NO_x emission rate for evaluation of SNCR and SCR costs is 0.17 lbs/MMBtu 30 day average. Although the Consent Decree includes alternate higher NO_x control limits for operation at less than 400 MW of the 805 MW design maximum, Colstrip Units 3&4 are baseload plants that operate greater than ninety-five percent of the time at more than 90% of maximum output. As documented in PPL Montana's January 31, 2011 submittal and EPA's Clean Air Markets Division (CAMD) website data, NO_x emissions at Colstrip Units 3 & 4 have averaged 0.17 lbs/MMBtu since the installation of the combustion controls for NO_x on Units 3&4. Consequently, 0.17 lbs/MMBtu is the appropriate baseline

⁵ In 2009, Unit 4 was out of service for approximately seven months for turbine repairs.

⁶ The permit limits are: For a 30 day rolling average, 0.18 #/MMBtu (loads > 400 GMW, 0.30 #/MMBtu (Loads <= 400 GMW, 1363 #/hour; for a 24 hour average, 0.25 #/MMBtu (loads > 400 GMW, 0.30 #/MMBtu (Loads <= 400 GMW, 1893 #/hour

⁷ Based upon current emission rates of 0.17 #/MMBtu and an uncontrolled emission rate of 0.90 #/MMBtu used in the Colstrip 3&4 Title V permit application.

⁸ It should be noted that operating hours and generation of Units 3 & 4 during 2006 and 2010 was/is reflective of normal operation as these units are baseload. In 2006, Unit 4 was in its 3-year maintenance overhaul cycle and its output is somewhat reduced.

emission rate to use in these analyses. The following sections describe the additional add-on control technology options presented herein to supplement the January 31, 2011 submission.

Year	NO _x Annual Average Emissions (#/MMBtu)	NO _x Annual Emissions (Tons)
2010 ⁹	0.17 (Unit 3); 0.17 (Unit 4)	4950 (Unit 3); 5095 (Unit 4)
2009	0.17 (Unit 3); 0.28 (Unit 4)	5036 (Unit 3); 3928 (Unit 4)
2008 ¹⁰	0.17 (Unit 3); 0.33 (Unit 4)	5245 (Unit 3); 11096 (Unit 4)
2007	0.24 (Unit 3); 0.40 (Unit 4)	8172 (Unit 3); 13650 (Unit 4)
2006	0.40 (Unit 3); 0.38 (Unit 4)	12856 (Unit 3); 11907 (Unit 4)

1.1 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., NH₃ or CO(NH₂)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 SO₂ or SO₃ 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 30 to 50% reductions when used alone and up to 65% reductions in total,

⁹ 2010 is the first full year of operation of Low-Nox burners on both Units 3 & 4

¹⁰ 2008 is the first full year of operation of low-Nox burners on Unit 3

when used in conjunction with combustion controls.¹¹ From the CCM and specifically speaking of the performance of SNCR technology:

“In typical field applications, however, it provides 30 to 50% reduction. Reductions of up to 65% have been reported for some field applications of SNCR in tandem with combustion control equipment such as low-NO_x burners (LNB).”

This means that for PPL Montana which already has achieved the reductions in NO_x emissions from 0.40 to 0.17 lbs/MMBtu in Unit 3, and from 0.38 to 0.17 lbs/MMBtu in Unit 4, representing (58% and 55% reductions in NO_x respectively) using combustion controls, SNCR would only be able to further reduce the 0.17 lbs/MMBtu by about another 7% to 10% (assuming the full 65% combined LNB/SNCR combination control is achieved).

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). For either Unit 3 or 4 this would mean that each unit would emit approximately 38 pounds per hour (148 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. There would also be reactions with other components of the exhaust and subsequently in the wet scrubbers currently in operation. 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.

1.2 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 reduced NO_x emission rates, the lowest emission rate attainable with the baseline emission rate of 0.17 lbs/MMBtu (see the EPA CAMD website and the January 31, 2011 PPL Montana submittal) at either Unit 3 or 4 is expected to be 0.06 lbs/MMBtu, or about a 65% reduction from 0.17 lbs/MMBtu.

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.

¹¹ EPA CCP, Section 4, NO_x Controls, page 1-3.

The location of the SCR unit would be downstream of the economizer and upstream of the air heater and wet scrubber. 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 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 two add-on, i.e. post combustion, control technologies are presented: SNCR, and SCR.

Two background reports are included in Attachment A that 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-1 and A-2.

2.1 SNCR Cost Analysis Using the IPM Methodology

Tables 2-1 and 2-2 show the results of application of the costing methodology developed for use by USEPA in the IPM regulatory studies. Table 2-1 presents the Colstrip specific parameters for Units 3&4 applied within the empirical cost analysis approach developed by S&L as presented in Attachment A-1. 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 believes that the presence of the PM and SO₂ scrubbers at Colstrip already limits the space available for the installation of reagent preparation equipment and reagent receipt and unloading operations. PPL has used a factor of 1.3 instead of the 1.0 that would characterize a more open site plan than that available at Colstrip.

SNCR uses urea that is injected into the combustion zone where it breaks down into two moles of ammonia and one mole of CO₂ 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 enter the PM/SO₂ scrubbers and cause unknown effects on the reaction chemistry. This could lead to higher fouling of scrubber components, increased maintenance, and more frequent breakdowns of the scrubbing equipment. Using the IPM methodology, and assuming that installation of an SNCR will result in an emission rate of 0.15 lbs/MMBtu the cost effectiveness is estimated to be \$10,336/ton. However, the operation of the SNCR will likely result in an increase in air heater fouling and result in an increase in forced outages. Even a one-day maintenance outage would increase the cost effectiveness by approximately \$3,300/ton. This cost is not included in the \$10,336 cost above.

2.2 SCR Cost Analysis Using the IPM Methodology

Tables 2-3 and 2-4 show the results of application of the S&L costing methodology to Colstrip Units 3&4 for SCR. The costs reflected in these tables reflect a retrofit factor of 2.1 based on PPL experience in estimating a retrofit of an SCR on a large coal-fired unit. That cost included \$10 million capital cost for installation of a dry sorbent system to reduce sulfuric acid that may be increased as a by-product of the SCR catalyst converting a small portion of the SO₂ to SO₃ and creating the potential for a visible plume. 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 Colstrip Units 3&4 is estimated to cost \$9,279/ton assuming an emission rate of 0.06 lbs/MMBtu. 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 effectiveness by approximately \$300/ton.¹²

3.0 Conclusion

Based on the high cost per ton of the estimated NO_x removed through installation of either an SNCR or an SCR at Colstrip Units 3 and 4, 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.

¹² This is less than the equivalent forced outage cost for an SNCR as the SCR removes more tons of NO_x.

Table 2-1
SNCR COSTING DEVELOPMENT
FOR CAPITAL AND OPERATION AND MAINTENANCE COSTS

Variable	Designation	Units	Value	Equation/Input ⁽¹⁾
SNCR CAPITAL COST FOR COLSTRIP UNITS 3 OR 4				
Unit Capacity (Gross)	A	(MW)	805	Input
Retrofit Factor	B		1.3	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	9,371	Input
NOx Emiss Rate	D	lbs/MMBtu	0.18	Uncontrolled
SO ₂ Emiss Rate	E	lbs/MMBtu	1.8	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	7.54E+09	A X C x 1000
Capacity Factor	I	(%)	89.0	Input
NOx Removal Eff	J	(%)	10.00	Input
NOx Removed	K	(lbs/hr)	135.79	D x H/10 ⁶ x J/10
Urea Rate	L	(lbs/hr)	590.37	K / 0.15/46 x 30
Water Required	M	(lbs/hr)	5313.36	L x 9
Dilution Water Rate	O	(1,000 gph)	0.64	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	(\$)	\$4,113,565	$B \times F / 1.05 \times 200000 \times (AxG)^{0.42}$
Air Heater Mods (not reqd)	BMA	(\$)	\$0	
Balance of Plant Costs	BMB	(\$)	\$4,428,115	$270000 \times A^{0.33} \times K^{0.12}$
Bare Module Cost	BM	(\$)	\$8,541,680	BMS + BMA + BMB
Engineering, Const Mgmt	A1	(\$)	\$854,168	10% of BM
Labor Adjustment	A2	(\$)	\$854,168	10% of BM
Contractor Profit, Fees	A3	(\$)	\$854,168	10% of BM
Cap, Eng, Const Cost	CECC	(\$)	\$11,104,184	BM + A1 + A2 + A3
Owners Cost	B1	(\$)	\$555,209	5% of CECC
Total Project Cost	TPC	(\$)	\$11,659,393	CECC + B1
Cost per kW		(\$)	14	\$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO	(\$)	\$62,400	2,080 hrs- 1- half time
Maintenance Material	FOMM	(\$)	\$102,500	1.2% of BM
Total Fixed O&M		(\$)	\$164,900	FOMO + FOMM
Urea Cost	VOMR	(\$)	\$132.83	L x P
Dilution Water Cost	VOMM	(\$)	\$0.64	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 2-2
PPL BART Cost Effectiveness Analysis
SNCR NOx Control
805 Megawatt Coal Fired Steam Electric Plant
Colstrip Unit 3 and Unit 4 (each)

Maximum Gross Heat Input	MM Btu/hr		7,572
Design Percent Load	%		89
Uncontrolled NOx Emissions (with PRB coal)	lbs/MMBtu		0.170
Exhaust Temperature, (°F)	T		405
Steam Turbine Power Output (TMW)	MW		805
Capacity Factor (89%)	hrs		7,796
Controlled NOx Emissions	lbs/MMBtu	See Note 3	0.158
Overall NOx Reduction Efficiency, (%)	%		7.06
Uncontrolled NOx Emissions, (lb/hr)			1287.2
Uncontrolled NOx Emissions, (tons/yr)			5017.9
Controlled NOx Emissions, (ton/yr)			4663.7
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)	14	\$11,659,393
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars) ⁽²⁾	\$12,028,663
Total Capital Costs, TCC		---	\$12,028,663
Direct Annual Costs, DAC	Urea Cost	VOMR	\$1,035,626
	Dilution Water Cost	VOMM	\$4,971
	Maintenance Cleanings ⁽⁴⁾		\$1,320,000
	Maintenance Labor	FOMO	\$62,400
	Maintenance Materials	FOMM	\$102,500
Total Direct Annual Costs, DAC			\$2,525,498
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	\$1,135,421
Total Indirect Annual Costs, IAC			\$1,135,421
Total Annual Costs, TAC = DAC + IAC			\$3,660,918
Cost Effectiveness (\$/ton pollutant Removed)			\$10,336

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= 113.065)
- 3) The controlled NOx emissions are adjusted to account for 148 tons of ammonia slip assuming that ammonia emissions are equivalent to NOx emissions on a ton for ton basis.
- 4) SNCR technology will cause fouling of the air preheater and require four cleanings per year at \$330,000 each

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

Variable	Designation	Units	Value	Equation/Input ⁽¹⁾
SCR CAPITAL COST FOR COLSTRIP UNITS 3 OR 4				
Unit Capacity (Gross)	A	(MW)	805	Input
Retrofit Factor	B		2.1	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	9,371	Input
NOx Emiss Rate	D	lbs/MMBtu	0.18	Uncontrolled
SO ₂ Emiss Rate	E	lbs/MMBtu	1.8	Uncontrolled
Type of Coal	F		PRB	Input
Coal Factor	G		1.05	Input
Heat Rate Factor	H		0.9371	C / 10,000
Heat Input	I	Btu/hr	7.54E+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)	950.50	D X I / 10 ⁶ * K / 100
Urea Rate	N	(lbs/hr)	664.04	M x 0.525 * 60/46 * 1.01/.99
Steam Required	M	(lbs/hr)	750.36	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	(\$)	\$171,722,024	180000 x B X L ^{0.2} x (AxGxH) ^{0.92}
Base Reagent Prep Cost	BMF	(\$)	\$2,276,523	410000 x M ^{0.25}
ID Fans, Anciliary Equip	BMB	(\$)	\$13,229,698	380000 x B x (AxGxH) ^{0.42}
Bare Module Cost	BM	(\$)	\$187,228,244	BMR + BMF + BMB
Engineering, Const Mgmt	A1	(\$)	\$18,722,824	10% of BM
Labor Adjustment	A2	(\$)	\$18,722,824	10% of BM
Contractor Profit, Fees	A3	(\$)	\$18,722,824	10% of BM
Cap, Eng, Const Cost	CECC	(\$)	\$243,396,718	BM + A1 + A2 + A3
Home office Costs	B1	(\$)	\$12,169,836	5% of CECC
Construction Funds	B2	(\$)	\$15,333,993	6% of CECC+B1
Total Project Cost	TPC	(\$)	\$270,900,547	CECC + B1 + B2
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		\$149.41	N X R
Steam Cost	VOMM		\$3.00	O x U
Catalyst cost ⁽³⁾	VOMW		\$0.35	\$/MW-hr

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 2-4
PPL BART Cost Effectiveness Analysis
SCR NOx Control
805 Megawatt Coal Fired Steam Electric Plant
Colstrip Unit 3 and Unit 4 (each)

Maximum Gross Heat Input	MM Btu/hr	7,572
Design Percent Load	%	89
LNCFS + SOFA Controlled NOx Emissions	lbs/MMBtu	0.170
Exhaust Temperature, (°F)	T	405
Steam Turbine Power Output (TMW)	MW	805
Capacity Factor (89%)	hrs	7,796
Controlled NOx Emissions	lbs/MMBtu	0.06
Overall NOx Reduction Efficiency, (%)	%	64.71
Uncontrolled NOx Emissions, (lb/hr)		1287.2
Uncontrolled NOx Emissions, (tons/yr)		5017.9
Controlled NOx Emissions, (ton/yr)		1771.0
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)	337	\$270,900,547
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars) ⁽²⁾	\$279,480,358
Total Capital Costs, TCC		---	\$279,480,358
Direct Annual Costs, DAC			
	Catalyst Cost ⁽³⁾	VOMW	\$2,196,636
	Urea Cost	VOMR	\$1,164,844
	Steam Cost	VOMM	\$23,400
	Maintenance Labor	FOMO	\$62,400
	Maintenance Materials	FOMM	\$300,000
Total Direct Annual Costs, DAC			\$3,747,280
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	\$26,380,969
Total Indirect Annual Costs, IAC			\$26,380,969
Total Annual Costs, TAC = DAC + IAC			\$30,128,249
Cost Effectiveness (\$/ton pollutant Removed)			\$9,279

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= 113.065)
- 3) Cost is for replacement and disposal based on S&L cost estimate in \$/MW-hr for PRB coal

ATTACHMENT A-1
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

The logo for Sargent & Lundy LLC features a stylized, grey, curved shape resembling a 'C' or a swoosh, positioned to the left of the company name. The name 'Sargent & Lundy' is written in a bold, blue, sans-serif font, with 'LLC' in a smaller, blue, sans-serif font to the right.

Sargent & Lundy LLC

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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 NO_x 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
- SO₂ 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 NO_x 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 SO₂ is above 3 lb/MMBtu, it is assumed that air heater modifications will be required. The unit heat rate factors into the amount of NO_x generated and ultimately the size of the

SNCR Cost Development Methodology – Final

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 NO_x 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 NO_x of 0.3 lb/MMBtu or lower and 25% for units with an inlet NO_x 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%

SNCR Cost Development Methodology – Final

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.



IPM Model – Revisions to Cost and Performance for
APC Technologies

Project No. 12301-007
August 20, 2010

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		Bituminous	<--- 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 construction subtotal
CECC (\$/kW) =	23	Capital, engineering and construction 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



IPM Model – Revisions to Cost and Performance for
APC Technologies

Project No. 12301-007
August 20, 2010

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	



IPM Model – Revisions to Cost and Performance for
APC Technologies

Project No. 12301-007
August 20, 2010

SNCR Cost Development Methodology – Final

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	<--- User Input
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 construction cost subtotal
CECC (\$/kW) =	17	Capital, engineering and construction 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



IPM Model – Revisions to Cost and Performance for
APC Technologies

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August 20, 2010

SNCR Cost Development Methodology – Final

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-2
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



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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, NO_x 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
- SO₂ 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 NO_x removal efficiency specifically affects the SCR catalyst, reagent and steam costs. The lower level of NO_x removal is recommended as:

- 0.07 NO_x lb/mmBtu – Bituminous
- 0.05 NO_x lb/mmBtu – PRB
- 0.05 NO_x 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

SCR Cost Development Methodology – Final

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.



SCR Cost Development Methodology – Final

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 construction cost subtotal
CECC (\$/kW) =	158	Capital, engineering and construction 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	