IPM Model – Updates to Cost and Performance for APC Technologies

SCR Cost Development Methodology

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Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly impact costs, such as flue gas volume, temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs a facility would incur to install a retrofit control such as project contingency.

Establishment of the Cost Basis

The 2004 to 2006 industry cost estimates for SCR units from 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" prepared for Midwest Ozone Group (MOG) were used by Sargent & Lundy LLC (S&L) to develop the SCR cost model. In addition, S&L included data from "Current Capital Cost and Cost-effectiveness of Power Plant Emissions Control Technologies" prepared by J. E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2010, and 2013. The published data were significantly augmented by the S&L in-house database of recent SCR projects. The current industry trend is to retrofit high-dust hot-side SCRs. The cold-side tail-end SCRs encompass a small minority of units and as such were not considered in this evaluation.

The data was converted to 2016 dollars based on the Chemical Engineering Plant Index (CEPI) data. Additional proprietary S&L in-house data from 2012 to 2016 were included to confirm the index validity. Finally, the cost estimation tool was benchmarked against recent SCR projects to confirm the applicability to the current market conditions.

The available data was analyzed in detail regarding project specifics such as coal type, NO_x reduction efficiency, and air pre-heater requirements. The 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. Based on the recently acquired data, it appears the overall capital cost has increased by approximately 15% over the costs published in 2013. Analysis of the data indicates that these units had a high degree of retrofit difficulty, high elevation, or low quality fuel.

The costs for retrofitting a plant smaller than 100 MW increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units. In light of the recent retirement of smaller than 200-MW size units, the evaluation of SCR technology may not be necessary. 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.

A combined SCR for small units is not a feasible option. The flue gas from the boiler is treated after the economizer in the SCR before entering the air heater. Thus, SCR is an integral part of the heat recovery cycle of an individual boiler. Each boiler has to be retrofitted with its own SCR reactor. Minor savings can be achieved by utilizing a common reagent storage and preparation system.

The least-squares curve fit was based upon an average of the SCR retrofit projects in recent years. Retrofit difficulties associated with an SCR may result in significant capital cost increases. A typical SCR retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9500 Btu/kWh;
- SO_2 Rate = < 3.0 lb/MMBtu;
- Type of Coal = Bituminous; and
- Project Execution = Multiple lump-sum contracts.

Methodology

Inputs

To predict 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 different typical heating values. 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 the difficulty of constructing 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.

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The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base SCR and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base SCR and balance of plant costs should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base SCR and balance of plant costs

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; and
- 0.05 NO_x lb/MMBtu – Lignite.

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

The base modules are:

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

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The total base module installed 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; and
- 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.

Fixed O&M (FOM)

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

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, half of an operator's time is required to monitor a retrofit SCR. The FOMO is based on that half-time requirement for the operations staff.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 0.5% of the BM for units less than 300 MW and 0.3% of the BM for units greater than or equal to 300 MW.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Catalyst replacement and disposal costs;
- Additional power required and unit power cost; and
- Steam required and unit steam cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs are tabulated on a per-megawatt-hour (MWh) basis.
- The reagent consumption rate is a function of unit size, NO_x feed rate, and removal efficiency.
- The catalyst replacement and disposal costs are based on the NO_x removal and total volume of catalyst required.
- The additional power required includes increased fan power to account for the added pressure drop and the power required for the reagent supply system. These requirements are a function of gross unit size and actual gas flow rate.
- The additional power is reported as a percent of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The steam usage is based upon reagent consumption rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Urea cost in $/ton. Due to escalation, urea cost was updated to reflect average 2016 pricing. The urea solution cost includes the cost of a 50% urea solution prepared at the manufacturing site with additives suitable for avoiding corrosion in the injectors and transportation cost. The solution cost is significantly higher than that of solid urea. If solid urea is purchased, it would require additional storage, solutionizing equipment, and additional deionized water processing capability at the plant site.
- Catalyst costs that include removal and disposal of existing catalyst and installation of new catalyst in $/cubic meter. No escalation has been observed for catalyst removal and disposal cost since 2013.
- Auxiliary power cost in $/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Steam cost in $/1000 lb.
- Operating labor rate (including all benefits) in $/hr.

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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
VOMP =	Variable O&M costs for additional auxiliary power
VOMM =	Variable O&M costs for steam

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 1 shows a complete capital and O&M cost estimate worksheet.

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Table 1. Example of a Complete Cost Estimate for an SCR System

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9500	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.3	<--- User Input
SO2 Rate	E	(lb/MMBtu)	3	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.95	C/10000
Heat Input	I	(Btu/hr)	4.75E+09	A*C*1000
NOx Removal Efficiency	K	(%)	75	<--- User Input
NOx Removal Factor	L		0.9375	K/80
NOx Removed	M	(lb/hr)	1069	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	747	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	845	N*1.13
Aux Power **Include in VOM?** ☑	**P**	**(%)**	**0.55**	0.56*(G*H)^0.43
Urea Cost (50% wt solution)	R	($/ton)	350	<--- User Input
Catalyst Cost	S	($/m3)	8000	<--- User Input (Includes removal and disposal of existing catalyst and installation of new catalyst)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Steam Cost	U	($/klb)	4	<--- User Input
Operating Labor Rate	V	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		**Example**	**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.			
BMR ($) =	310000*(B)*(L)^0.2*(A*G*H)^0.92	$ 88,780,000	SCR (ductwork modifications and strengthening, reactor, bypass) island cost
BMF ($) =	564000*(M)^0.25	$ 3,225,000	Base reagent preparation cost
BMA ($) =	IF E ≥ 3 AND F=Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$ 8,446,000	Air heater modification / SO3 control (Bituminous only & > 3lb/MMBtu)
BMB ($) =	529000*(B)*(A*G*H)^0.42	$ 7,042,000	ID or booster fans & auxiliary power modification costs
BM ($) =	BMR + BMF + BMA + BMB	$ 107,493,000	Total bare module cost including retrofit factor
BM ($/KW) =		215	Base cost per kW
Total Project Cost			
A1 = 10% of BM		$ 10,749,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 10,749,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 10,749,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$ 139,740,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**279**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 6,987,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		$ 146,727,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**293**	Total project cost per kW without AFUDC
B2 = 6% of (CECC + B1)		$ 8,804,000	AFUDC (Based on a 2 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$ 155,531,000**	Total project cost
TPC ($/kW) =		**311**	Total project cost per kW

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Table 1 Continued

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9500	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.3	<--- User Input
SO2 Rate	E	(lb/MMBtu)	3	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.95	C/10000
Heat Input	I	(Btu/hr)	4.75E+09	A*C*1000
NOx Removal Efficiency	K	(%)	75	<--- User Input
NOx Removal Factor	L		0.9375	K/80
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Catalyst Cost	S	($/m3)	8000	<--- User Input (Includes removal and disposal of existing catalyst and installation of new catalyst)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Steam Cost	U	($/klb)	4	<--- User Input
Operating Labor Rate	V	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (1/2 operator time assumed)*2080*V/(A*1000)	$	0.13	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = (IF A < 300 then 0.005*BM ELSE 0.003*BM)/(B*A*1000)	$	0.64	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.78**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = N*R/(A*1000)	$	0.52	Variable O&M costs for Urea
VOMW ($/MWh) = (0.4*(G^2.9)*(L^0.71)*S)/(8760)	$	0.35	Variable O&M costs for catalyst: replacement & disposal
VOMP ($/MWh) =P*T*10	$	0.33	Variable O&M costs for additional auxiliary power required including additional fan power
VOMM ($/MWh) = O*U/A/1000	$	0.01	Variable O&M costs for steam
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**1.20**	