IPM Model – Updates to Cost and Performance for APC Technologies

SNCR Cost Development Methodology for Oil/Gas-fired Boilers

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Purpose of IPM Model

Cost algorithms in the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications, and do not take into consideration site-specific cost issues. The primary purpose of the IPM cost modules 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. By necessity, the cost algorithms were designed to require minimal site-specific information. The IPM cost equations can provide order-of-magnitude capital costs for various air quality control systems based only on a limited number of inputs such as unit size, gross heat rate, inlet NOx level, fuel sulfur level, % 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. Finally, 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 Cost Basis

The 2021 coal-fired boilers IPM SNCR module was used as an input to this module along with S&L in-house information for oil and gas applications to adjust the cost factors. This module was benchmarked against recent SNCR projects to confirm the applicability to the current market conditions. The S&L in-house database of project costs were converted to 2021 dollars based on an escalation factor of 2.5% based on the industry trends over the last ten years (2010 – 2020) excluding the current market conditions[1].

The higher 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 that may require upgrades to accommodate the new SNCR control system.

The S&L data includes SNCR projects with various types of boilers, fuels, sulfur levels and retrofit complexities. The typical SNCR retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = < 3 lb/MMBtu;
- Type of Fuel = Natural Gas and Oil; and
- Project Execution = Multiple lump sum contracts.

Methodology

[1] To escalate prices from Jan 2021 to July 2022 costs, an escalation factor of 19.5% should be used, based on the Handy Whitman steam production plant index.

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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. 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 NOx rate and removal efficiency will impact the amount of urea required and size of the reagent handling equipment. Finally, the boiler type will influence the capital costs of the SNCR system and balance of plant considerations.

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 SNCR costs are directly impacted by the site elevation. This base cost module should be increased based on the ratio of the atmospheric pressure between sea level and 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 SNCR cost should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base SNCR cost

The NOx removal efficiency achievable with SNCR is limited by unit size and inlet NOx concentrations. The SNCR efficiency is significantly lower for large boilers compared to small boilers primarily due to the large penetration required for urea droplets to cover the flue gas. The highest efficiency that could be achieved is approximately 15% for units greater than 400 MW, 20% for units 200-400 MW, and 25% for units smaller than 200 MW. For all applications a target floor of 0.08 lb/MMBtu is the lowest outlet NOx emission rate that can be reliably achieved by SNCR technology throughout the operating load range. Lower emission rates may periodically be achieved when the unit is operating at lower loads.

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;
- Water treatment for the dilution water; and
- Retrofit difficulty.

The base modules are:

BMS = Base SNCR system

BMA = Base air heater modifications, as required

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BMB =	Base balance of plant costs including: piping, site upgrades, water treatment for the dilution water, etc...
BM =	BMS + BMA + BMB

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 0% of the CECC and owner's costs as these projects are expected to be completed in less than a year after the equipment is released for the fabrication.

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 SNCR 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 were tabulated on a per kilowatt-year (kW yr) basis.
- In general, 0 additional operators are required a new SNCR system.
- The fixed maintenance materials and labor is a direct function of the process capital cost at 1.2% of the BM.
- The administrative labor is a function of the FOMO and FOMM at 3% of (FOMO + 0.4FOMM).

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Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Dilution water required and unit water cost;
- Additional power required and unit power cost; and
- Boiler efficiency reduction due to the added water in the boiler and unit replacement coal cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.
- The reagent usage is a function of the amount of NOx removed, NOx inlet rate, and boiler type. A utilization factor (UF) 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.
- The dilution water usage is based on creating a 5% dilute reagent stream for injection into the boiler.
- The additional power required includes compressed air or blower requirements for the urea injection system and the reagent supply system.
- 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.
- Impacts on the unit heat rate due to injection of liquid water into the boiler are accounted for by additional coal costs to provide added boiler heat input and can be included in the total variable costs.

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 for a 50% by weight solution in $/ton;
- Auxiliary power cost in $/kWh;
- Dilution water cost in $/1000 gallon;
- Operating labor rate (including all benefits) in $/hr; and
- Replacement coal cost in $/MMBtu.

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

VOMP = Variable O&M costs for additional auxiliary power

VOMB = Variable O&M costs for additional coal

The total VOM is the sum of VOMR, VOMM, VOMP, and VOMB. Table 1 shows a complete capital and O&M cost estimate worksheet for an SNCR on a T-fired boiler.

Oil/Gas-Fired SNCR Cost Development Methodology

Table 1. Example Complete Cost Estimate for an SNCR System Installed on a T-fired boiler

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		Tangential	<--- User Input
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)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Fuel	F		Natural gas	<--- User Input
Fuel Factor	G		1.00	Natural Gas=1.0, Oil=1.06
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	15	
NOx Removed	L	(lb/hr)	162	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	703	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	13358	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.32	1175*N/I*100
Aux Power **Include in VOM?** ☑	O	(%)	0.05	0.05 default value
Dilution Water Rate	P	(1000 gph)	1.60	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2021 dollars

Capital Cost Calculation	Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BMS ($) = BT*B*G*202400*(A*H)^0.42; (IF CFB then BT=0.75, ELSE BT=1)	$	2,730,000	SNCR (injectors, blowers, DCS, reagent system) cost
BMB ($) = BT*(L^0.12)*358400*(A)^0.33; (IF CFB then BT=0.75, ELSE BT=1)	$	5,129,000	Balance of plant cost (piping, site upgrades, water treatment for the dilution water, etc...)
BM ($) = BMS + BMA + BMB	$	7,859,000	Total bare module cost including retrofit factor
BM ($/KW) =		16	Base cost per kW
Total Project Cost			
A1 = 10% of BM	$	786,000	Engineering and Construction Management costs
A2 = 10% of BM	$	786,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM	$	786,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3	**$**	**10,217,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**20**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	511,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	$	10,728,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**21**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1	**$**	**10,728,000**	Total project cost
TPC ($/kW) =		**21**	Total project cost per kW

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Boiler Type	BT		Tangential	<--- User Input
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Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Fuel	F		Natural gas	<--- User Input
Fuel Factor	G		1.00	Natural Gas=1.0, Oil=1.06
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	15	
NOx Removed	L	(lb/hr)	162	D*I/10^6*K/100
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Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2021 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (No operator time assumed)*2080*T/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.012/(B*A*1000)	$	0.19	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.00	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.19**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*Q/A/1000	$	0.49	Variable O&M costs for Urea
VOMM ($/MWh) = P*S/A	$	0.00	Variable O&M costs for dilution water
VOMP ($/MWh) = O*R*10	$	0.03	Variable O&M costs for additional auxiliary power required.
VOMB ($/MWh) = 0.001175*N*U/A	$	0.06	Variable O&M costs for heat rate increase due to water injected into the boiler
VOM ($/MWh) = VOMR + VOMM + VOMP + VOMB	**$**	**0.59**	