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Cost of Selective Catalytic Reduction (SCR) Application for NO_X Control on Coal-fired Boilers

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Abstract

This report provides a methodology for estimating budgetary costs associated with retrofit applications of selective catalytic reduction (SCR) technology on coal-fired boilers. SCR is a post-combustion nitrogen oxides (NO_X) control technology capable of providing NO_X reductions in excess of 90 percent. With SCR, NO_X reductions are achieved by injecting ammonia into the flue gas, which then passes through layers of catalyst in a reactor. The ammonia and NO_X react on the surface of the catalyst, forming molecular nitrogen and water. In the United States, SCR has been applied mainly to electrical utility boilers firing coal and natural gas and ranging in capacity from 25 to 800 megawatts (MW).

The costing methodology presented in this report is applicable to SCR retrofits on coal-fired boilers ranging in capacity from 100 MW to approximately 850 MW and with design efficiencies greater than 80 percent and up to 95 percent of NO_X removal. The cost equations and variables used in the methodology are based on information obtained from SCR system suppliers and reflect experience gained from over 200 SCR applications. It is noted, however, that the budgetary cost estimates for typical SCR applications that this methodology can provide cannot replace the detailed site-specific engineering cost studies or cost quotations that are developed by SCR system suppliers.

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Chapter 1
Introduction

Selective catalytic reduction (SCR) is a post-combustion nitrogen oxides (NO_X) control technology capable of providing NO_X reductions in excess of 90 percent.[1] With SCR, NO_X reductions are achieved by injecting ammonia (NH_3) into the flue gas, which then passes through layers of catalyst in a reactor. The NH_3 and NO_X react on the surface of the catalyst, forming molecular nitrogen (N_2) and water.

SCR has been applied to stationary source, fossil-fuel-fired combustion units for NO_X emission control since the early 1970s and is currently being used in Japan, Europe, and the United States.[2,3,4] It has been applied to large utility and industrial boilers, process heaters, and combined cycle gas turbines. In the United States, SCR has been applied mainly to electrical utility boilers firing coal and natural gas ranging in size from 25 to 800 megawatts (MW).

This report provides a methodology for estimating budgetary costs associated with typical retrofit applications of selective catalytic reduction (SCR) technology on coal-fired boilers. The cost equations and variables used in the methodology are based on information obtained from SCR system suppliers and reflect experience gained from over 200 SCR applications. It is noted, however, that the budgetary cost estimates for typical SCR applications that this methodology can provide cannot replace the detailed site-specific engineering cost studies or cost quotations that are developed by SCR system suppliers.

The cost estimates developed using the costing methodology have been considered in the context of estimates made using other approaches [5,6,7,8] as well as estimates from reported case studies.[9,10,11] In general, there tends to be good agreement between predictions of this methodology and reported estimates of capital and operation and maintenance (O&M) costs.

Chapter 2
Description of the SCR Technology

In the SCR process, NH_3 is injected into the flue gas within a temperature range of about 315 to 400 °C (600 to 750 °F), upstream of a catalyst. Subsequently, as the flue gas contacts the SCR catalyst, NO_X, which predominantly is NO in combustion devices, is chemically reduced to nitrogen as follows:

$$2NO + 2NH_3 + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O \qquad (1)$$

Figure 1 shows the process layout of an SCR system in which the catalyst is located between the economizer and the air preheater. This process layout, known as hot-side SCR, is most commonly used in SCR applications.

Equation (1) indicates that, theoretically, 1 mole of NH_3 is required to reduce 1 mole of NO. Any unreacted NH_3 released from the SCR system, known as NH_3 slip, is undesirable because it may combine with sulfur dioxide (SO_2) and sulfur trioxide (SO_3) in the flue gas to generate ammonium sulfate and bisulfate compounds that may cause fouling of downstream equipment, especially the air preheater. By maintaining close to the theoretical stoichiometry, the NH_3 slip can be kept at acceptable levels in properly designed modern SCR systems,[12] while NO_X reductions in excess of 90 percent can be achieved.

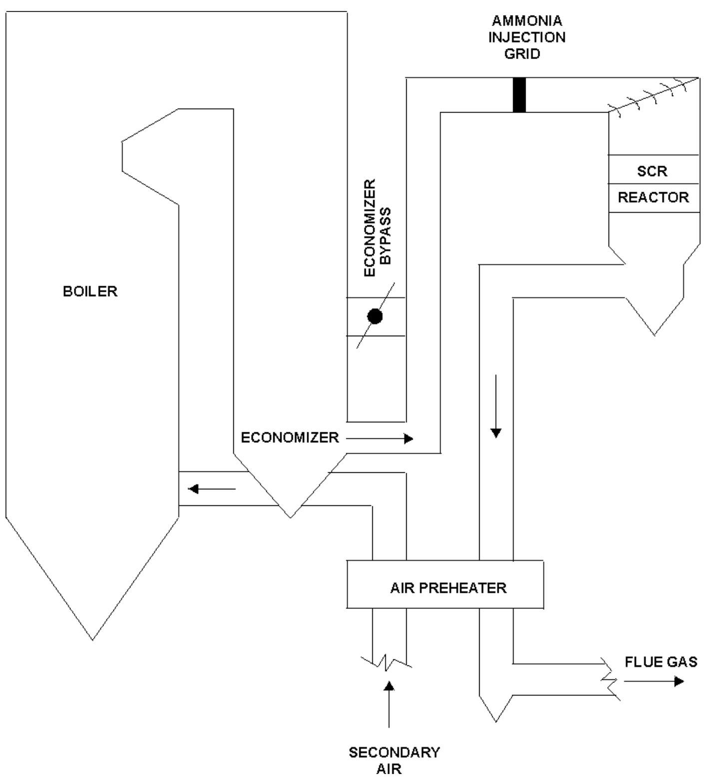

Figure 1. Process flow schematic for an SCR application.

NO_X reduction with NH_3 is exothermic, resulting in the release of heat. However, because the NO_X concentration in the flue gas at the inlet of the SCR is typically 0.02 to 0.01 percent by volume, the amount of heat released is correspondingly small.

With a properly designed and controlled NH_3 injection rate and typically 2 to 4 percent excess oxygen, the NO_X reduction reactions achieve completion, provided the reaction temperature is maintained within the required range.

The catalyst plays a central role in this NO_X control technology. Originally, SCR catalysts were made of precious metals such as platinum. In Japan, researchers started using base metals consisting of vanadium, titanium, and tungsten in the late 1970s, thereby significantly reducing costs. Further improvements in catalyst formulations have resulted in decreased unwanted side reactions such as SO_2 to SO_3 conversions, increased resistance to flue gas poisons, and increased catalyst activity. As a consequence, catalyst volumes needed to achieve a given level of NO_X reduction have decreased and the operating life of catalysts has increased.

SCR systems have been operating for many years on fossil-fuel-fired boilers in Japan, Europe, and the United States and have experienced relatively few operational or maintenance problems. Thus, SCR is considered to be a NO_X control technology that is capable of providing a high degree of NO_X reduction in a reliable manner.

Chapter 3
Description of the Costing Methodology

The methodology is applicable to SCR retrofits on coal-fired boilers with design efficiencies greater than 80 percent and up to 95 percent of NO_X removal. The methodology was not extended to lower NO_X removal efficiencies for several reasons. First, in general, there has been less of a demand for achieving low NO_X removal efficiencies (i.e., below 70-75 percent) with SCR.[13,14,15,16] This is because, typically, SCR systems with higher NO_X removal efficiencies are more cost effective. Second, the procedures for obtaining budgetary cost estimates at lower NO_X removal efficiencies are already available.[7] Finally, SCR systems designed for lower NO_X removal efficiencies often may be more applicable to unique applications such as SNCR/SCR hybrid systems;[16,17,18] however, such applications are not in the scope of this work.

The methodology can be applied to coal-fired boilers ranging in capacity from 100 to approximately 850 MW and is applicable to all coal-fired boiler types. The range of inlet NO_X (i.e., NO_X concentration at the inlet of the SCR reactor) in this methodology can vary between 0.15 and 2.5 $lb/10^6$ Btu of NO_X. The costing equations and variables are based on experience gained at over 200 SCR applications in the U.S. and around the world. Data fit constants used in these equations are also based on industry data. In general, as a budgetary costing procedure not intended to be a substitute for a more detailed unit specific study, the methodology is thought to slightly overestimate cost in most cases.

Chapter 4
Costing Algorithms

Costing algorithms for capital, fixed O&M, and variable O&M costs are described in this section.

Capital Cost

The capital cost of a SCR retrofit is estimated in $/kW (January 2000 dollars) using Equation (2) below:

$$D = 75\ \{300{,}000\ [(B/1.5)^{0.05}\ (C/100)^{0.4}]/A\}^{0.35} \qquad (2)$$

where:

D = capital cost ($/kW)
75 = capital cost ($/kW) associated with a typical SCR retrofit on a 300,000 kW coal-fired unit
300,000 = reference to a 300,000 kW baseline unit (basis for the economy-of-scale adjustment in the equation)
B = NO_X (lb/10^6 Btu) at the inlet of SCR reactor; range of approximately 0.15 – 2.5 lb/10^6 Btu
1.5 = reference NO_X concentration in lb/10^6 Btu at SCR inlet
0.05 = exponent for inlet NO_X concentration [13]
C = NO_X removal efficiency (percent); range of greater than 80 and up to 95 percent
0.4 = exponent for NO_X removal efficiency [13]
A = plant capacity (kW); range of approximately 100,000 – 850,000 kW
0.35 = exponent for an economy-of-scale adjustment factor (scaled from 300,000 kW unit) [16,19]

The capital cost estimated by Equation (2) accounts for the costs associated with equipment, installation, engineering, contingency, spare parts, and commissioning. However, this cost does not include an allowance for funds during construction (AFDC) because of a relatively short construction schedule associated with typical SCR installations. Note that capital cost as estimated by Equation (2) is a function of three primary parameters: plant capacity (kW), initial NO_X (lb/10^6 Btu), and NO_X removal efficiency (percent). Additional comments on these parameters are provided below.

Plant Capacity

The capital cost equation is reliable for plant capacities in the 100 MW to 850 MW range. As noted above, the capital cost equation was derived based on a 300 MW unit. Capital cost estimates for units other than 300 MW are obtained by the application of a scaling factor. Applying this equation to capacities significantly greater than 850 MW could result in economy-of-scale benefits that would not normally occur.[16] However, in situations where SCR retrofits are considered for significantly larger capacity units (e.g., two 1300 MW boilers at the Gavin and Cumberland facilities), the combined capacity is often split between multiple air heaters and catalyst reactors. For example, two 1300 MW capacity units could be treated by utilizing three air heaters and three catalyst reactors, each with approximately 867 MW capacity.[16] Therefore, units significantly larger than 850 MW can generally be accommodated by this methodology.

Inlet NO_X
Equation (2) is reliable for inlet NO_X in the range of 0.15 and 2.5 lb/10^6 Btu. This range would accommodate most coal-fired boilers including uncontrolled cyclone units that operate with inlet NO_X in the range of approximately 0.9 to 2.5 lb/10^6 Btu.

NO_X Removal Efficiency
The capital cost equation is reliable for NO_X reduction efficiencies greater than 80 and up to 95 percent. Note that these efficiencies depend on catalyst specifications including formulation and size. These specifications, as well as the associated reactor size, will vary from manufacturer to manufacturer and are proprietary.

Design and Installation [13,14,16,20]
The costing methodology presented in this report is for a typical (or average) SCR retrofit and, therefore, assumes a generic SCR system design and installation. With this constraint, the methodology is not suitable for estimating detailed site-specific costs of an SCR application. The following discussion briefly explains the major elements that can influence the cost of an SCR retrofit and how they were accommodated in the methodology.

The major design elements that can influence the cost of an SCR retrofit on a coal-fired boiler are:

- reagent storage, vaporizer, dilution fan/chamber, piping, and injection grid;
- ductwork for flue gas, and economizer bypass;
- SCR reactor bypass;
- air heater modifications;
- soot blowers and modification to ash handling system;
- fans and electrical supply and equipment;
- SCR reactor(s) and catalyst;
- structural steel;
- foundations;
- enclosures; and
- instrumentation and controls.

The extent of incorporation of the above elements in an SCR system design is dependent on the plant layout. For example, a relatively constrained plant layout may involve a more difficult SCR system design compared to a relatively unconstrained layout and, therefore, may require more ductwork and air heater modifications. In contrast, a relatively unconstrained layout may not need air heater modifications and more than the typical amount of ductwork. To account for varying levels of design complexity, a degree of difficulty is associated with an SCR retrofit application.[13,14,16, 21] In this context, the average degree of difficulty is assigned to a retrofit where the SCR installation is relatively simple (i.e., the facility has adequate space for the SCR system). Equation (2) assumes this average degree of difficulty.

Although the capital cost equation applies only to SCR retrofits on coal-fired boilers, it can be used to develop estimates for new coal-fired unit SCR applications. Generally, these latter applications will experience less design and installation constraints since the SCR is part of the overall plant design and construction. Therefore, in general, the capital cost of a retrofit application would be 20-50 percent higher compared to that of a new application.[9]

Fixed Operation and Maintenance (O&M) Cost

The fixed O&M cost is a function of the capital cost estimate and is estimated using Equation (3) below:

$$E = D * A * C \tag{3}$$

where:

E = fixed O&M cost ($/yr)
D = capital cost ($/kW) from Equation (2)
A = plant capacity (kW); range of approximately 100,000 – 850,000 kW
C = a constant; 0.0066 yr^{-1}

The fixed O&M cost is the sum of the annual maintenance material and labor cost, and is estimated to be 0.66 percent [16] of the capital cost. It should be noted that while assumptions of as much as 2 percent have been used in a number of other estimation methods, information from recent case studies have shown this value to generate fixed cost estimates that are generally too high. For example, the assumption of 2 percent along with 80 $/kW for a 300 MW application would result in a fixed O&M cost of 480,000 $/yr, a value much higher than approximately $100,000 associated with boiler capacities of 300 to 350 MW.[9] However, it should be noted that fixed O&M cost tends to be a small portion of the annual cost associated with application of any NO_X control technology. It is also important to note that Equation (3) does not include the cost associated with catalyst replacement. In this methodology, catalyst replacement cost is included in the variable O&M cost estimate.

Variable O&M Cost

The variable O&M cost, F, is estimated in $/yr using Equation (4):

$$F = G\,[225 * (0.37B * H * C/100 * 8760/2000) * 1.005 * 1.05 + 0.025 * D * A * \{(B/1.5)^{0.05}\,(C/100)^{0.4}\} + 1.45 * A] \tag{4}$$

As expressed above, Equation (4) addresses the costs associated with reagent usage, catalyst replacement, and energy consumption. These costs are calculated as follows.

$$NH_3 \text{ use cost (\$/yr)} = G * 225 * (0.37B * H * C/100 * 8760/2000) * 1.005 * 1.05 \tag{4a}$$

where:

G = annual capacity factor (expressed as a fraction)
225 = anhydrous NH_3 cost in $/ton
0.37 = molecular weight of NH_3/molecular weight of NO_X measured as NO_2 = 17.03/46.01
B = inlet NO_X (lb/10^6 Btu); range of 0.15 – 2.5 lb/10^6 Btu
H = heat input (10^6 Btu/hr)
C = NO_X removal efficiency (percent); range of greater than 80 and up to 95 percent
8760 = hr/year
2000 = lb to ton conversion
1.005 = design margin that accounts for NH_3 slip (see the appendix)
1.05 = design margin that accounts for small amount of NO_2 in flue gas (SCR chemistry requires 2 moles of NH_3 per mole of NO_2 instead of 1 mole of NH_3 per 1 mole of NO)

Annual catalyst replacement cost (\$/yr) = $G * 0.025 * D * A * [(B/1.5)^{0.05} (C/100)^{0.4}]$ (4b)

where:

G = annual capacity factor (expressed as a fraction)
0.025 = catalyst deactivation factor for coal-fired units (yr^{-1}).[13,14,16]
D = capital cost (\$/kW)
A = plant capacity (kW); range of approximately 100,000 – 850,000 kW
B = inlet NO_X ($lb/10^6$ Btu); range of 0.15 – 2.5 $lb/10^6$ Btu
1.5 = reference NO_X concentration in $lb/10^6$ Btu at SCR inlet
0.05 = exponent for inlet NO_X
C = NO_X removal efficiency (percent); range of greater than 80 and up to 95 percent
0.4 = exponent for percent NO_X removal efficiency[13]

Note that, based on information from industry, 0.025 was selected as the default factor associated with catalyst replacement in Equation (4b).[16] However, it is important to note that this factor is likely to remain debatable among catalyst, as well as system, suppliers. The factor of 0.025 assumes that one catalyst layer would be replaced approximately every 15,000 and 20,000 hours of operation. Other values of this factor have been suggested,[13, 16] including values as high as 0.075, and as low as 0.01. The lower the factor, the slower the catalyst deactivation being assumed. Given the importance of catalyst cost, changing factors over a broad range can result in a significantly increased (or decreased) estimate for variable O&M cost. Selection of the default factor of 0.025 is consistent with the overall approach of this methodology of developing conservative cost estimates for typical or average SCR retrofit applications. This factor is dependent upon the number of hours a unit is assumed to operate per year. The factor of 0.025 assumes full-year operation of the catalyst (i.e., no bypass). If the catalyst is used only during an ozone season (typically a 5-month period), the number of useful years for the catalyst could increase, warranting a lower value for the factor. This variable can also change as a function of fuel quality (e.g., use of high/low sulfur or more/less arsenic content of coal). Generally, the more “difficult” is the fuel for SCR application (e.g., Powder River Basin coal with potential for catalyst masking due to high ash alkalinity), the higher is the factor. In such a context, a higher factor (possibly approaching 0.075) could be deemed reasonable in Equation (4b).[13,14,16]

In Equation (4b), the average catalyst life is assumed to be approximately 15,000 to 20,000 hours.[6,16] In this methodology, a “three plus one” layer catalyst arrangement is assumed (three catalyst support layers plus one “spare/dummy” layer). This arrangement includes a spare catalyst layer and has an advantage such that only one catalyst layer is replaced at the end of 15,000-20,000 hours. There is also an underlying assumption that the catalyst cost[6,16] is \$8000/m^3, which may be more representative of the current catalyst market, rather than the historical market (e.g., some studies have noted catalyst cost at existing retrofits closer to \$11,000 to \$14,000 /m^3).[9]

Energy requirement cost (\$/yr)[17] = $G * 1.45 * A$ (4c)

where:

G = annual capacity factor (expressed as a fraction)
1.45 = a constant (\$/kW-yr) = 0.03 (cost of energy in \$/kWh) * 8760 (h/yr) * 0.0055 (fraction cost of auxiliary power/unit of generation)
A = plant capacity (kW); range of approximately 100,000 – 850,000 kW

Note that power cost assumes that typical coal-fired SCR applications use 0.5 to 0.6 percent of the total auxiliary power cost. Therefore, 0.55 percent is used as a default.[16] Additionally, an assumption of 6 to 7 inches (15.24 to 17.78 cm) of water pressure drop through the SCR system is implicit in Equation (4c).[16]

Table 1 presents a summary of equations presented in this section and illustrates their use through an example. Further, Table 2 presents cost estimates calculated with the methodology for SCR retrofits on a range of plant capacities with varying NO_X reduction requirements.

Chapter 5
Validation of the Costing Methodology

The costing methodology was derived from information provided by SCR system suppliers and is deemed valid for typical coal-fired SCR retrofit applications for NO_X removal efficiencies greater than 80 and up to 95 percent. However, it is important to note that this methodology is intended and valid for developing budgetary cost estimates and assumes typical installations. Therefore, the methodology should not be expected to account for reported costs of each site-specific SCR retrofit application.

In a 1998 study [9] conducted for Northeast States for Coordinated Air Use Management (NESCAUM) and Mid-Atlantic Regional Air Management Association (MARAMA), the capital cost for SCR retrofit on dry-bottom wall- and tangentially fired boilers to achieve 85 percent NO_X reduction was estimated to be between 70 and 90 $/kW. Similarly, the study estimated that capital cost of SCR retrofits to achieve 90 percent NO_X reduction from wet-bottom boilers would also range between 70 and 90 $/kW. Note that these estimates were based on 330 MW units. In comparison, the costing methodology results in an estimate of approximately 70 $/kW for similar units.

Recent literature reflects a range of 55 to 140 $/kW as being typical of site-specific retrofit SCR capital costs for all types of utility boilers.[8] By comparison, the costing methodology estimates a capital cost range of approximately 50 to 110 $/kW to achieve 85 to 95 percent NO_X removal efficiency.

The NESCAUM/MARAMA report (in Appendix D) estimated a combined fixed and variable O&M cost of reducing NO_X by 70 to 80 percent for a 330 MW dry bottom boiler at approximately $1.1 million/yr and approximately $2.8 million/yr for a similar-sized wet bottom boiler.[9] The costing methodology estimates the combined fixed and variable O&M costs for all boiler types to be about $1.0 million/yr to $1.7 million/yr for 85 percent NO_X removal and initial NO_X ranging between 0.45 and 1.5 lb/10^6Btu. In another economic analysis by Gaikwad and Boward,[6] for SCR retrofits on 300 and 500 MW boilers to reduce NO_X by 80-85 percent, combined O&M costs were estimated to be between $1.6 million/yr and $3.2 million/yr.

Based on above comparisons, the capital and O&M cost estimates derived from applying this methodology are deemed reasonably accurate and fall well within the ranges reported elsewhere.[9,16] Actual cost reported from site-specific SCR retrofit applications, as well as individual facility engineering studies, would more accurately reflect the circumstances of individual facilities. As a result, it is also reasonable to expect that reported actual costs may not always conform to budgetary cost estimates that have been designed around typical installations. While the methodology has been shown to consistently estimate costs that fit well with other reported actual and estimated costs, occasionally it can be expected that there will be data with higher or lower costs.

Chapter 6
Conclusions

This report provides a costing methodology for estimating budgetary costs associated with retrofit applications of SCR technology on coal-fired boilers. The methodology is applicable to SCR retrofits on coal-fired boilers ranging in capacity from 100 to approximately 850 MW and with design efficiencies greater than 80 and up to 95 percent of NO_X removal.

The cost equations and variables used in the methodology are based on information obtained from SCR system suppliers and reflect experience gained from over 200 SCR applications in the U.S. and abroad. Data fit constants used in the cost equations are also based on industry data.

The capital and O&M cost estimates derived from applying this methodology fall well within the ranges reported elsewhere. For example, recent literature reflects a range of 55 to 140 $/kW as being characteristic of retrofit SCR system capital cost for all types of utility boilers. By comparison, the costing methodology estimates a capital cost range of approximately 50 to 110 $/kW to achieve 85 to 95 percent NO_X removal efficiency.

The costing methodology presented in this report can be used to estimate budgetary costs of SCR application over the spectrum of boiler sizes and types. However, the estimates that this methodology can provide cannot replace the detailed site-specific engineering cost studies or cost quotations. Actual cost reported from site-specific SCR retrofit applications, as well as individual facility engineering studies would more accurately reflect specific circumstances of an individual installation. In general, the methodology is thought to slightly overestimate cost in most cases.

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Table 1. A summary of equations used in the costing methodology.

Cost Basis: January 2000 dollars		
Capital Cost		
Capital Cost Equation:	**D =**	**75 * (300,000 ((B/1.5)^.05*(C/100)^0.4)/A)^0.35**
Plant Capacity, kW	A	
Initial NO_x, lb/10^6 Btu	B	
NO_x Reduction Efficiency, %	C	
Capital Cost, $/kW	D	
For example, if A=600000 kW, B=0.45 lb/MBtu, C=85%		
D, $/kW = 56.32		

Fixed O&M Cost		
Fixed O&M Cost Equation:	**E =**	**D * A * 0.0066**
Plant Capacity, kW	A	
Capital Cost, $/kW	D	
Fixed O&M Cost, $/yr	E	
For example, if A = 600000 kW, D = 56.32		
E, $/yr = 223,027.20		

Variable O&M Cost		
Variable O&M Cost Equation:	**F =**	**G*(225*(0.37*B*H*C/100*8760/2000)*1.005*1.05 + 0.025*D*A*((B/1.5)^.05*(C/100)^.4) + 1.45 *A)**
Plant Capacity, kW	A	
Initial NOx, lb/10^6 Btu	B	
NO_x Reduction Efficiency, %	C	
Capital Cost, $/kW	D	
Annual Capacity Factor	G	
Heat Input to Boiler, 10^6 Btu/hr	H	
Variable O&M Cost, $/yr	F	
For example, if A=600000 kW, B=0.45 lb/10^6 Btu, C=85%, D=$56.32/kW, G=0.65, H=6000 10^6Btu/hr		
F, $/yr = 1,623,993.96		

Table 2. Calculation of Cost Estimates using the costing methodology.
(Costs are based on January 2000 dollars)

EXAMPLE 1

NO_x Reduction Efficiency, %	85	85	85	85	85	85	85	85
Plant Capacity, kW	100,000	200,000	300,000	400,000	500,000	600,000	700,000	800,000
Boiler Heat Input, 10^6Btu/hr	1000	2000	3000	4000	5000	6000	7000	8000
Initial NO_x, lb/10^6Btu	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Capital Cost, $/kW	105.44	82.73	71.78	64.91	60.03	56.32	53.36	50.93
Fixed O&M, $/yr	69,593.06	109,203	142,132.94	171,358.20	198,105.45	223,030.48	246,535.60	268,889.85
Variable Cost, $/yr	341,097.81	617,061.77	878,513.39	1,131,917.58	1,379,938.58	1,624,001.09	1,864,979.01	2,103,456.82

EXAMPLE 2

NO_x Reduction Efficiency, %	90	90	90	90	90	90	90	90
Plant Capacity, kW	100,000	200,000	300,000	400,000	500,000	600,000	700,000	800,000
Boiler Heat Input, 10^6Btu/hr	1000	2000	3000	4000	5000	6000	7000	8000
Initial NO_x, lb/10^6Btu	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Capital Cost, $/kW	106.29	83.39	72.36	65.43	60.51	56.77	53.79	51.34
Fixed O&M, $/yr	70,152.19	110,081	143,274.87	172,734.94	199,697.08	224,822.37	248,516.33	271,050.18
Variable Cost, $/yr	351,464.30	635,753.01	905,074.46	1,166,096.22	1,421,566.04	1,672,953.29	1,921,159.25	2,166,786.74

EXAMPLE 3

NO_x Reduction Efficiency, %	95	95	95	95	95	95	95	95
Plant Capacity, kW	100,000	200,000	300,000	400,000	500,000	600,000	700,000	800,000
Boiler Heat Input, 10^6Btu/hr	1000	2000	3000	4000	5000	6000	7000	8000
Initial NO_x, lb/10^6Btu	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Capital Cost, $/kW	107.10	84.03	72.91	65.93	60.97	57.20	54.20	51.73
Fixed O&M, $/yr	70,685.21	110,917	144,363.49	174,047.41	201,214.40	226,530.60	250,404.59	273,109.66
Variable Cost, $/yr	361,711.13	654,256.49	931,391.16	1,199,980.24	1,462,852.91	1,721,522.04	1,976,915.63	2,229,654.37

EXAMPLE 4

NO_x Reduction Efficiency, %	85	85	85	85	85	85	85	85
Plant Capacity, kW	100,000	200,000	300,000	400,000	500,000	600,000	700,000	800,000
Boiler Heat Input, 10^6Btu/hr	1000	2000	3000	4000	5000	6000	7000	8000
Initial NO_x, lb/10^6Btu	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Capital Cost, $/kW	107.69	84.49	73.31	66.29	61.31	57.52	54.50	52.01
Fixed O&M, $/yr	71,074.90	111,528	145,159.38	175,006.94	202,323.71	227,779.48	251,785.09	274,615.33
Variable Cost, $/yr	577,118.23	1,083,588.27	1,574,317.33	2,056,317.65	2,532,479.03	3,004,346.78	3,472,868.80	3,938,679.05

Appendix

Determination of the Design Margin Accounting for Ammonia Slip

NO_x (ppm) = NO_x (lb $NO_2/10^6$Btu)*1/46.01(lb-mole NO_2/lb NO_2)*9780 (10^6Btu/dscf)*
22.4 (normal L/g-mole flue gas)*530/430 (standard L/normal L)*
10^3 (cm^3/L)*1/$(12*2.54)^3$ (ft^3/cm^3)*
453.6 (g-mole flue gas/lb-mole flue gas)*(20.9-3)/(20.9)*10^6 (A1)

where 9780 (10^6Btu/dscf) is the F-factor for bituminous coal and the factor (20.9-3)/20.9 accounts for the fact that NO_x (ppm) is generally measured at 3% oxygen (O_2) in flue gas.

Simplifying Eqn. (A1),

NO_x (ppm) = 786.88 NO_x (lb $NO_2/10^6$Btu) (A2)

As seen in Eqn. (1), 1 mole of NH_3 is needed for each mole of NO_x reduced. Consider an NH_3 slip of x (ppm). Then a mass balance of NH_3 yields:

$(NH_3)_i$ (ppm) = $(NO_x)_r$ (ppm) + x (ppm) (A3)

where $(NH_3)_i$ (ppm) relates to the amount of NH_3 injected into flue gas to provide a NO_x reduction of $(NO_x)_r$ (ppm) and resulting in a slip of x (ppm).

Rearranging Eqn. (A3),

$(NH_3)_i$ (ppm)/$(NO_x)_r$ (ppm) = 1 + x (ppm)/$(NO_x)_r$ (ppm) (A4)

Substituing Eqn. (A2) in (A4),

$(NH_3)_i$ (ppm)/$(NO_x)_r$ (ppm) = 1 + x (ppm)/[786.88*$(NO_x)_r$ (lb/10^6 Btu)] (A5)

$(NO_x)_r$ (lb/10^6 Btu) = B (lb/10^6 Btu)*C/100 (A6)

where

B = NO_X (lb/10^6 Btu) at the inlet of SCR reactor
C = NO_X removal efficiency (percent)

Substituting Eqn. (A6) in (A5),
$(NH_3)_i$ (ppm)/$(NO_x)_r$ (ppm) = 1 + x (ppm)/[786.88*B (lb/10^6 Btu)*C/100] (A7)

In general, B can range from 0.3 ($lb/10^6 Btu$) for a coal-fired boiler equipped with state-of-the-art combustion controls to 2.5 ($lb/10^6 Btu$) for an uncontrolled cyclone-fired boiler. Assume x = 2 ppm and C = 85 percent. Then using these values in Eqn. (A7),

$1.001 \leq (NH_3)_i \text{ (ppm)}/(NO_x)_r \text{ (ppm)} \leq 1.009$

Thus, on average, a design margin of 1.005 would account for NH_3 slip.