Appendix 5.1 SO_2 Scrubber Engineering Cost Equations

Below is an abbreviated summary of the engineering cost equations for state-of-the-art applications of three flue gas desulfurization technologies: limestone forced oxidation (LSFO), lime spray drying (LSD), and magnesium enhanced lime (MEL). A full presentation of the equations appears in U.S. Environmental Protection Agency, Office of Research and Development, *Controlling SO_2 Emissions: A Review of Technologies* (EPA-600/R-00-093), October 2000 with additional information published in a subsequent journal article[1]. These equations provided the basis for deriving the capital, FOM, and VOM cost of SO_2 scrubbers in EPA Base Case 2000.

Capital Costs

Adjusted Total Capital Requirement (Adjusted TCR)

$$Adjusted\ TCR\ (\$/kW) = C_1 \times \frac{TCR}{MW}$$

where C_1 is a correction to account for the cumulative effects of variables with minor cost impact
C_1 = 1.1024 for LSFO
C_1 = 1.0365 for LSD

Total Capital Requirement (TCR)

$$TCR\ (\$) = 1.02 \times TPI + \frac{FOM}{12} + \frac{VOM}{CF \times 12} + INVENTORY$$

where *FOM* (\$) is the fixed operation and maintenance cost,
VOM (\$) is the variable operation and maintenance cost,
CF is the plant capacity factor, i.e., the ratio of average output to rated output of a plant on an annual basis,
INVENTORY (\$) is the inventory capital, i.e., the cost of reagent required to meet the bulk storage requirement. A 30-day limestone inventory and \$15/ton limestone cost was assumed for LSFO. Similarly, a 30-day lime inventory and \$50/ton lime cost was assumed.

Total Plant Investment (TPI)

$$TPI = TPC \times (F_{TCE} + F_{AFDC})$$

where F_{TCE} is the financial factor "Total cash expended" which de-escalates cost for inflation, and F_{AFDC} is the financial factor "Funds during construction" which accounts for interest during construction.

Total Plant Cost (TPC)

$$TPC = BM \times \left(1 + \frac{A_1}{100} + \frac{A_2}{100} + \frac{A_3}{100}\right) \times \left(1 + \frac{B}{100}\right) \times \left(1 + \frac{C}{100}\right) + R_F$$

where *BM* is sum of the "bare module" capital cost of the five major equipment areas. It is multiplied by the following contingency factors to obtain the TPC:

[1]Srivastava, R.K. and W. Jozewicz, "Flue Gas Desulfurization: The State of the Art," *Journal of the Air and Waste Management Association,* December 2001, pp.1676-1688.

A_1 is the general facilities contingency (assumed to be 5%),
A_2 is the engineering home office contingency (assumed to be 10%),
A_3 is the process contingency (assumed to be 5%),
B is the project contingency (assumed to be 15%), and
C is the prime contractor's fee (assumed to be 3%)
R_F is the retrofit factor (assumed to be 1.3).

Capital Cost (BM)

$$BM = BM_F + BM_R + BM_G + BM_W + BM_E$$

where BM_F is the bare module capital cost of the reagent feed equipment,
BM_R is the bare module capital cost of the SO_2 removal equipment,
BM_G is the bare module capital cost of the flue gas handling equipment,
BM_W is the bare module capital cost of the waste handling equipment, and
BM_E is the bare module capital cost of the support equipment.

Bare Module Capital Cost (BM) for State-of-the-Art Model

Limestone Forced Oxidation	Lime Spray Drying	Magnesium-Enhanced Lime
Reagent Feed Equipment (BM_F)	**Reagent Feed Equipment (BM_F)**	**Reagent Feed Equipment (BM_F)**
$BM_F = \left[-0.0034 \cdot \left[\frac{FR_L}{1000}\right]^4\right] + \left[2.1128 \cdot \left[\frac{FR_L}{1000}\right]^3\right] - \left[494.55 \cdot \left[\frac{FR_L}{1000}\right]^2\right] + 68164.7 \cdot \frac{FR_L}{1000} + 7118470 + C_{B\&H} + C_{DBA}$ where $C_{B\&H}$ is the cost of the ball mill and hydrocyclones C_{DBA} is the cost of the DBA tank FR_L is the reagent feed rate (lb/hr) FR_{SO2} is the SO_2 flow rate (lbs/hr) *Wt%S* is the coal sulfur content *HR* is the heat rate (Btu/kWh) *MWe* is the LSFO size (MWe) *HHV* is the coal heating value (Btu/lb) – fixed at 11,900 Btu/lb	$BM_F = \left[170023 \cdot \frac{FR_L}{1000} + 3764611\right] + 72338 \cdot F_{GPM}^{0.3195}$ where FR_L is the reagent feed rate (lb/hr) F_{GPM} is the slurry flow rate (gpm) FR_{SO2} is the SO_2 flow rate *Wt%S* is the coal sulfur content *HR* is the heat rate (Btu/kWh) *MWe* is the LSD size (MWe) *HHV* is the coal heating value (Btu/lb) – fixed at 11,900 Btu/lb	$BM_F = 170023 \cdot \frac{FR_L}{1000} + 3764611 + 72338 \cdot F_{GPM}^{0.3195}$ where FR_L is the reagent feed rate (lb/hr) F_{GPM} is the slurry flow rate(gpm) *Wt%S* is the coal sulfur content *HR* is the heat rate (Btu/kWh) *MWe* is the MEL size (MWe) *HHV* is the coal heating value (Btu/lb) – fixed at 11,900 Btu/lb
$C_{B\&H} = 32.9 \cdot \left[\frac{FR_L}{2000}\right]^2 + 22412 \cdot \left[\frac{FR_L}{2000}\right] + 1854902$ $C_{DBA} = 364627 \cdot \left[\frac{\frac{FR_{SO_2} \cdot \frac{0.95 \cdot 20}{2000}}{8.34 \cdot (1+0.5)}}{60}\right]^{0.283}$ $FR_L = FR_{SO_2} \cdot 1.05 \cdot \frac{100}{64} \cdot \frac{0.90}{0.953}$ $FR_{SO_2} = \frac{Wt\%S \cdot 1000}{HHV} \cdot \left[\frac{64}{32}\right] \cdot MW_e \cdot HR$	$FR_L = FR_{SO_2} \cdot 1.75 \cdot \frac{56}{64} + FR_{SO_2} \cdot 1.75 \cdot \frac{56}{64} \cdot \frac{1-0.9}{0.9}$ $F_{GPM} = \frac{FR_L \cdot \frac{74}{56} + FR_L \cdot \frac{74}{56} \cdot \frac{1-0.3}{0.3}}{8.34 \cdot \left[\frac{1+0.3}{60}\right]}$ $FR_{SO_2} = \frac{Wt\%S \cdot 1000}{HHV} \cdot \left[\frac{64}{32}\right] \cdot MW_e \cdot HR$	$FR_L = FR_{SO_2} \cdot 1.0 \cdot \frac{56}{64} \cdot \frac{0.98}{0.94}$ $F_{GPM} = \frac{FR_L \cdot \frac{74}{56} + FR_L \cdot \frac{74}{56} \cdot \frac{1-0.3}{0.3}}{8.34 \cdot \left[\frac{1+0.3}{60}\right]}$ $FR_{SO_2} = \frac{Wt\%S \cdot 1000}{HHV} \cdot \left[\frac{64}{32}\right] \cdot MW_e \cdot HR$

Removal Equipment (BM_R)

$$BM_R = BARE\ MODULE_R + ABSORBER \bullet N_a + PUMP \bullet N_p$$

where $BARE\ MODULE_R$ is the auxiliary cost for the SO_2 removal area
$ABSORBER$ is the absorber cost, 1 or 2 depending on RLCS or alloy material construction respectively. Model assumes average.
N_a is the number of absorbers
$PUMPS$ is the cost of the pumps
N_p is the number of pumps
F_{GPM} is the slurry flow rate
$ACFM$ is the flue gas flow into the absorber (in cfm)
P is the % O_2 in the stack (8% assumed)

$$BARE\ MODULE_R = 0.8701 \bullet \left[\frac{FR_{SO_2}}{1000}\right]^3 - 188.2 \bullet \left[\frac{FR_{SO_2}}{1000}\right]^2 + 34809 \bullet \left[\frac{FR_{SO_2}}{1000}\right] + 1905302$$

$$ABSORBER\ 1 = 173978 \bullet \left[\frac{ACFM}{1000}\right]^{0.5575}$$

$$ABSORBER\ 2 = 230064 \bullet \left[\frac{ACFM}{1000}\right]^{0.5638}$$

$$PUMPS = 910.85 \bullet \left[\frac{F_{GPM}}{N_p}\right]^{0.5954} \bullet N_p$$

$$ACFM = \frac{1000}{10^6} \bullet \frac{9780}{60} \bullet \frac{(460+295)}{528} \bullet \frac{100}{(100-6)} \bullet MW_e \bullet HR \bullet \left[\frac{0.04}{P} + \frac{0.209}{P} \bullet \frac{(P-0.04)}{(0.209-P)}\right]$$

$$N_a = Roundup\left(\frac{MW}{900}\right)$$

Removal Equipment (BM_R)

$$BM_R = BARE\ MODULE_R + SPRAY\ DRYERS$$

where $BARE\ MODULE_R$ is the auxiliary cost for the SO_2 removal area
$SPRAY\ DRYER1$ is the cost of SO_2 removal (1 or 2) depending on RLCS or alloy material construction respectively.
$ACFM$ is the flue gas flow into the absorber (in cfm)
P is the % O_2 in the stack (8% assumed)
N_a is the number of absorbers

$$BARE\ MODULE_R = N_a[581877809 \bullet Wt\%S^3 - 3653117 \bullet Wt\%S^2 + 693335 \bullet Wt\%S + 214198] + 677421 \bullet Wt\%S^{-0.0966}$$

$$SPRAY\ DRYER1 = \left[-3.57 \bullet \left[\frac{ACFM}{N_a \bullet 1000}\right]^2 + 9246 \bullet \left[\frac{ACFM}{N_a \bullet 1000}\right] + 791896\right]$$

$$ACFM = \frac{1000}{10^6} \bullet \frac{9780}{60} \bullet \frac{(460+295)}{528} \bullet \frac{100}{(100-6)} \bullet MW_e \bullet HR \bullet \left[\frac{0.04}{P} + \frac{0.209}{P} \bullet \frac{(P-0.04)}{(0.209-P)}\right]$$

$$N_a = Roundup\left(\frac{MW}{275}\right)$$

Removal Equipment (BM_R)

$$BM_R = BARE\ MODULE_R + ABSORBER + PUMPS$$

where $BARE\ MODULE_R$ is the auxiliary cost for the SO_2 removal area
$ABSORBER$ is the absorber cost, 1 or 2 depending on RLCS or alloy material construction respectively. Model assumes average.
N_a is the number of absorbers
$PUMPS$ is the cost of the pumps
N_p is the number of pumps
$ACFM$ is the flue gas flow into the absorber (in cfm)
P is the % O_2 in the stack (8% assumed)

$$BARE\ MODULE_R = 0.825 \bullet \left[0.8701 \bullet \left[\frac{FR_{SO_2}}{1000}\right]^3 - 188.2 \bullet \left[\frac{FR_{SO_2}}{1000}\right]^2 + 34809 \bullet \left[\frac{FR_{SO_2}}{1000}\right] + 1905302\right]$$

$$ABSORBER\ 1 = 173978 \bullet 0.9 \bullet \left[\frac{ACFM}{1000}\right]^{0.5575}$$

$$ABSORBER\ 2 = 230064 \bullet 0.9 \bullet \left[\frac{ACFM}{1000}\right]^{0.5638}$$

$$PUMPS = 0.8 \bullet 910.85 \bullet \left[\frac{F_{GPM}}{N_p}\right]^{0.5954} \bullet N_p$$

$$ACFM = \frac{1000}{10^6} \bullet \frac{9780}{60} \bullet \frac{(460+295)}{528} \bullet \frac{100}{(100-6)} \bullet MW_e \bullet HR \bullet \left[\frac{0.04}{P} + \frac{0.209}{P} \bullet \frac{(P-0.04)}{(0.209-P)}\right]$$

$$N_a = Roundup\left(\frac{MW}{280}\right)$$

Flue Gas Handling Equipment (BM_G)

$$BM_G = BARE\ MODULE_G + ID\ FANS$$

where *BARE MODULE*$_G$ is the auxiliary cost of the flue gas handling area
ID FANS is the cost of fans
N_f is the number of fans

$$BARE\ MODULE_G = -0.1195\cdot\left[\frac{ACFM}{1000}\right]^2 + 777.76\cdot\left[\frac{ACFM}{1000}\right] + 238203 + 0.000012\cdot\left[\frac{ACFM}{1000}\right]^3 - 0.1651\cdot\left[\frac{ACFM}{1000}\right]^2 + 1288.82\cdot\left[\frac{ACFM}{1000}\right] + 559693 - 0.2009\cdot\left[\frac{ACFM1}{1000\cdot N_a}\right]^2 + 1266.4\cdot\left[\frac{ACFM1}{1000\cdot N_a}\right] + 420141$$

where *ACFM1* is the flue gas flow rate out of the absorber (cfm)

$$ID\ FANS = 91.24\cdot\left[\frac{ACFM}{N_f}\right]^{0.6842}\cdot N_f$$

$$ACFM_1 = ACFM\cdot\frac{(460+127)}{(460+295)}\cdot\frac{(100-6)}{(100-14)}$$

Flue Gas Handling Equipment (BM_G)

$$BM_G = BARE\ MODULE_G + ID\ FANS$$

where *BARE MODULE*$_G$ is the auxiliary cost of the flue gas handling area
ID FANS is the cost of fans
N_f is the number of fans

$$BARE\ MODULE_G = \left[1721.8\cdot\left[\frac{ACFM}{1000}\right]^{0.683} + 1326.2\cdot\left[\frac{ACFM1}{1000}\right]^{0.7191}\right]\cdot N_a + \left[15338\cdot\left[\frac{ACFM}{1000}\right]^{0.5} + 47680\cdot\left[\frac{ACFM1}{1000}\right]^{0.5576}\right] + \left[4840.4\cdot\left[\frac{ACFM2}{1000}\right]^{0.5} + 2695.9\cdot\left[\frac{ACFM3}{1000}\right]^{0.5}\right]$$

where *ACFM1*, *ACFM2*, and *ACFM3* are flue gas flow rates at the exit from the absorber, particulate control device, and ID fans, respectively (cfm)

$$ID\ FANS = 91.24\cdot\left[\frac{ACFM2}{N_f}\right]^{0.6842}\cdot N_f$$

$$ACFM_1 = ACFM\cdot\frac{(460+147)}{(460+295)}\cdot\frac{(100-6)}{(100-14)}\cdot\frac{29.92}{(29.4-17\cdot 7.355x10^{-2})}$$

$$ACFM_2 = ACFM\cdot\frac{(460+147)}{(460+295)}\cdot\frac{(100-6)}{(100-14)}\cdot\frac{29.92}{(29.4-23\cdot 7.355x10^{-2})}$$

$$ACFM_3 = ACFM\cdot\frac{(460+152)}{(460+295)}\cdot\frac{(100-6)}{(100-14)}\cdot\frac{29.92}{(29.4+1\cdot 7.355x10^{-2})}$$

Flue Gas Handling Equipment (BM_G)

$$BM_G = BARE\ MODULE_G + ID\ FANS$$

where *BARE MODULE*$_G$ is the auxiliary cost of the flue gas handling area
ID FANS is the cost of fans
N_f is the number of fans

$$BARE\ MODULE_G = -0.1195\cdot\left[\frac{ACFM}{1000}\right]^2 + 777.76\cdot\left[\frac{ACFM}{1000}\right] + 238203 - -0.2009\cdot\left[\frac{ACFM1}{1000\cdot N_a}\right]^2 + 1266.4\cdot\left[\frac{ACFM1}{1000\cdot N_a}\right] + 420141 + 0.000012\cdot\left[\frac{ACFM}{1000}\right]^3 - 0.1651\cdot\left[\frac{ACFM}{1000}\right]^2 + 1288.82\cdot\left[\frac{ACFM}{1000}\right] + 559693$$

where *ACFM1* is the flue gas flow rate out of the absorber (cfm)

$$ID\ FANS = 91.24\cdot\left[\frac{ACFM}{N_f}\right]^{0.6842}\cdot N_f$$

$$ACFM_1 = ACFM\cdot\frac{(460+127)}{(460+295)}\cdot\frac{(100-6)}{(100-14)}$$

Waste/By-product Handling Area (BM_w)	Waste/By-product Handling Area (BM_w)	Waste/By-product Handling Area (BM_w)
$BM_W = BARE\ MODULE_W + THICKENER$ where *BARE MODULE*$_W$ depends on the disposal option: *W1* is the system with gypsum stacking *W2* is the system with landfill *W3* is the system with wallboard gypsum production *THICKENER* is the cost of thickener $BM_W = 0.5\ [BM_{W1} + BM_{W3}]$ $BM_{W1} = -4.0567\cdot\left[\frac{FR_{SO_2}}{1000}\right]^2 + 1788\cdot\left[\frac{FR_{SO_2}}{1000}\right] + 80700$ $BM_{W2} = 0.325\cdot\left[\frac{FR_{SO_2}}{1000}\right]^3 - 168.77\cdot\left[\frac{FR_{SO_2}}{1000}\right]^2 + 29091\cdot\left[\frac{FR_{SO_2}}{1000}\right] + 773243$ $BM_{W3} = BM_{W2}\cdot 1.25$ $THICKENER = 9018.7\cdot FR_{SO_2}\cdot 0.95\cdot\frac{172}{64\cdot 2000} + 114562$	$BM_W = 2051841884\cdot Wt\%S^2 - 1443163\cdot Wt\%S + 1026479$	$BM_W = BARE\ MODULE_W + THICKENER$ where *BARE MODULE*$_W$ is the auxiliary cost of the waste disposal *THICKENER* is the cost of thickener Wallboard production is assumed $BARE\ MODULE_W = \left[0.325\cdot\left[\frac{FR_{SO_2}}{1000}\right]^3 - 168.77\cdot\left[\frac{FR_{SO_2}}{1000}\right]^2 + 29091\cdot\left[\frac{FR_{SO_2}}{1000}\right] + 773243\right]\cdot 1.25\cdot 0.825$ $THICKENER = 9018.7\cdot FR_{SO_2}\cdot 0.95\cdot\frac{172}{64\cdot 2000} + 114562\cdot 0.825$

Support Equipment Area (BM_E)	Support Equipment Area (BM_E)	Support Equipment Area (BM_E)
$BM_E = BARE\ MODULE_E + CHIMNEY$ where *BARE MODULE*$_E$ was the auxiliary cost *CHIMNEY 1* was chimney cost with reheat *CHIMNEY2* was chimney cost without reheat $BARE\ MODULE_E = 0.0003 \cdot MW_e^3 - 1.0677 \cdot MW_e^2 + 1993.8 \cdot MW_e + 1177674$ $CHIMNEY_1 = 40208 \cdot ACFM1^{0.3339}$ $CHIMNEY_2 = 23370 \cdot ACFM1^{0.3908}$ $CHIMNEY = 0.5[CHIMNEY_1 + CHIMNEY_2]$	$BM_E = -1.211 \cdot MW_e^2 + 2704.2 \cdot MW_e + 1354716.2 + CHIMNEY$ where *CHIMNEY* was based on the chimney cost without reheat $CHIMNEY = 23370 \cdot ACFM3^{0.3908}$	$BM_E = BARE\ MODULE_E + CHIMNEY$ where *BARE MODULE*$_E$ was the auxiliary cost *CHIMNEY 1* was chimney cost with reheat *CHIMNEY2* was chimney cost without reheat $BARE\ MODULE_E = 0.825 \cdot \left[0.0003 \cdot MW_e^3 - 1.0667 \cdot MW_e^2 + 1993.8 \cdot MW_e + 1177674 \right]$ $CHIMNEY_1 = 40208 \cdot ACFM1^{0.3339}$ $CHIMNEY_2 = 23370 \cdot ACFM1^{0.3908}$ $CHIMNEY = 0.5[CHIMNEY_1 + CHIMNEY_2]$

Fixed Operation and Maintenance (FOM) Cost

$FOM = OL + ML\&M + A\&S$ where *OL* is the cost of operating labor *ML&M* is the maintenance and materials cost *A&S* is the administration and support cost		
Limestone Forced Oxidation	**Lime Spray Drying**	**Magnesium-Enhanced Lime**
$OL = 41.69041 \cdot MW_e^{-0.322307} \cdot \frac{MW_e \cdot 30 \cdot 40 \cdot 52}{100}$	$OL = [18.25 - 2.278 \cdot \ln(MW_e)] \cdot \frac{MW_e \cdot 30 \cdot 40 \cdot 52}{100}$	$OL = 41.69041 \cdot MW_e^{-0.322307} \cdot \frac{MW_e \cdot 30 \cdot 40 \cdot 52}{100}$
$ML\&M = 0.03 \cdot BM$	$ML\&M = 0.02 \cdot BM$	$ML\&M = 0.03 \cdot BM$
$A\&S = 0.3 \cdot (0.4 \cdot ML\&M + OL)$	$A\&S = 0.3 \cdot (0.4 \cdot ML\&M + OL)$	$A\&S = 0.3 \cdot (0.4 \cdot ML\&M + OL)$

Variable Operation and Maintenance (VOM) Cost

Limestone Forced Oxidation	Lime Spray Drying	Magnesium-Enhanced Lime
$VOM = C_{CaCO3} + C_{DBA} + 0.5[C_{DS} - CREDIT] + STEAM + POWER$ where C_{CaCO3} is the cost of limestone (unit price at \$15/ton) C_{DBA} is the cost of dibasic acid (unit price at \$430/ton) C_{DS} is the cost of disposal using gypsum stacking (\$6/ton) *CREDIT* is the by-product credit with wallboard production (\$2/ton) *STEAM* is the cost of steam (\$3.50/1000 lb). Average of reheat and no reheat. *POWER* is the cost of electrical power consumed for LSFO *TER* is the thermal energy required to reheat steam (lb/hr). Assumed 25° reheat, c_p=0.244 Btu/(lb °F) from air, density = 0.0765 (lb/ft^3)	$VOM = C_{CaO} + C_{DL} + POWER + FRESH\ WATER\ COST$ where C_{CaO} is the cost of lime (unit price at \$65/ton) C_{DL} is the cost of disposal (\$30/ton) *POWER* is the cost of energy consumed for LSD *FRESH WATER* is the cost of water	$VOM = C_{CaO} + POWER - CREDIT + STEAM$ where C_{CaO} is the cost of magnesium enhanced lime (unit price at \$50/ton) *POWER* is the cost of energy consumed for MEL
Reagent Cost	**Reagent Cost**	**Reagent Cost**
$C_{CaCO_3} = \frac{FR_L}{2000} \bullet 8760 \bullet CF \bullet 15$ where FR_L is the limestone feed rate *CF* is the capacity factor	$C_{CaO} = \frac{FR_L}{2000} \bullet 8760 \bullet CF \bullet 50$ where FR_L is the lime feed rate *CF* is the capacity factor	$C_{CaO} = \frac{FR_L}{2000} \bullet 8760 \bullet CF \bullet 50$ where FR_L is the limestone feed rate *CF* is the capacity factor
Dibasic Acid Cost	**Disposal Cost**	**CREDIT**
$C_{DBA} = 430 \bullet 8760 \bullet CF \bullet FR_{SO_2} \bullet \frac{0.95}{2000} \bullet \frac{20}{2000}$ where $FR_{SO\,2}$ is the SO_2 flow rate	$C_{DL} = \frac{8760}{2000} \bullet CF \bullet 12 \bullet (FR_{SO_2} \bullet \frac{129}{64} + MW_e \bullet 1000 \bullet 0.1 \bullet \frac{HR}{HHV})$ where $FR_{SO\,2}$ is the SO_2 flow rate	$CREDIT = 2 \bullet 8760 \bullet CF \bullet FR_{SO_2} \bullet 0.95 \bullet \frac{172}{64 \bullet 2000}$ where $FR_{SO\,2}$ is the SO_2 flow rate

Disposal Cost	Fresh Water Cost	Energy Cost
$C_{DS} = 6 \bullet 8760 \bullet CF \bullet FR_{SO_2} \bullet 0.95 \bullet \frac{172}{64 \bullet 2000}$ $CREDIT = 2 \bullet 8760 \bullet CF \bullet FR_{SO_2} \bullet 0.95 \bullet \frac{172}{64 \bullet 2000}$ $DISPOSAL = 0.5[C_{DS} - CREDIT]$	$FRESH\ WATER\ COST = FR_L \bullet 1.1 \bullet \frac{18}{56} \bullet CF \bullet 8760 \bullet 0.454 \bullet 1 \bullet \frac{1}{3.785} \bullet \frac{0.6}{1000}$ Assumes the unit cost of water = 0.6 mills/gal (from cue cost)	$POWER = 0.0105 \bullet \frac{1000 \bullet MW_e \bullet 0.8231}{1000} \bullet 8760 \bullet CF \bullet 25$
Steam Cost	**Energy Cost**	**Steam Cost**
$STEAM = 0.5 \bullet 3.5 \bullet 8760 \bullet CF \bullet \frac{TER}{855.14 \bullet 1000}$ $TER = 0.244 \bullet 25 \bullet ACFM_1 \bullet \frac{(460+60)}{(460+127)} \bullet 0.0765 \bullet 60$ **Energy Cost** $POWER = 25 \bullet 8760 \bullet CF \bullet 0.02 \bullet \frac{1000 \bullet MW_e \bullet 0.8231}{1000}$	$POWER = 0.007 \bullet \frac{1000 \bullet MW_e}{1000} \bullet 8760 \bullet CF \bullet 25$	$STEAM = 0.5 \bullet 3.5 \bullet 8760 \bullet CF \bullet \frac{TER}{855.14 \bullet 1000}$ $TER = 0.244 \bullet 25 \bullet ACFM_1 \bullet \frac{(460+60)}{(460+127)} \bullet 0.0765 \bullet 60$

Appendix 5.2 Combustion Control and Policy NO_X Rates

EPA Winter 1998 Base Case assumptions on combustion control and policy NO_x rates were retained in EPA Base Case 2000. For readability, the relevant sections describing the combustion control and policy NO_x rate assumptions in EPA Winter 1998 Base Case have been reproduced in full below.[2] In certain instances, EPA Base Case 2000 modified or redefined some of the assumptions from EPA Winter 1998 Base Case. Such information has been italicized and underlined.

A 5.2.1 Combustion Control

In the NO_x control program options that EPA examines, the Agency assumes that NO_x combustion controls are an initial step that is taken by coal-fired units that are above 25 MW. The estimates of the costs and NO_x rates that result are determined outside of IPM.

The estimates of NO_x combustion control costs depend on three factors:

1. **Geographic Coverage of Control Option** – Costs will only exist in the portion of the United States that a NO_x control program that EPA is analyzing covers. *Since the SIP Call is explicitly modeled in the EPA Base Case 2000, all fossil units in the SIP Call states include combustion controls.*

2. **Baseline Use of Combustion Controls** – *In the EPA Base Case 2000, fossil-fueled units in the SIP Call region are assumed to have NO_x combustion controls already in place. Therefore, no additional reductions due to NO_x combustion controls are assumed for these units under policy scenarios regulating NO_x.* There are also some units that have combustion controls in place to comply with NSPS provisions. In addition, many units will have these combustion controls in place to comply with the Title IV NO_x requirements. The cost of a control option is the incremental cost of placing controls on the remaining units that are covered. The EPA Base Case 2000 retains the information that EPA developed under the EPA Winter 1998 Base Case to sort out which coal-fired units would be adding combustion controls[3].

3. **Unit Costs Depending on Size and Utilization Rate of Units** – The costs are estimated for each individual unit and the cost equations that EPA uses in the analysis consider unit size, and in most cases vary by utilization rate. Although the Agency uses unit specific information of the size of units, it has used the conservative generic assumption of units operating with an 80 percent capacity factor to estimate variable costs. Also, for estimating the costs for wall-fired and tangentially-fired units, the Agency has considered low NO_x burners without Overfire Air (LNB without OFA) and low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1), respectively.

This section contains two more subsections. The first area provides cost and performance assumptions used for combustion controls. The second area explains how EPA developed the "NO_x policy rates" reflecting the application of combustion controls.

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[2] "Analyzing Electric Power Generation Under CAAA," Office of Air and Radiation, US Environmental Protection Agency, March 1998, pages A5-2 to A5-6.

[3] For the EPA Winter 1998 Base Case, EPA used the supporting analysis for the Regulatory Impact Analysis of NO_x Regulations, October 24, 1996, to identify coal-fired units that would be adding combustion controls to comply with the Title IV regulations that *were mandated to go into* full effect in the year 2000.

Costs and Performance Assumptions

The costs and performances listed below are used to calculate policy NO_x rates and to estimate the costs of installation of combustion controls to comply with NO_x control options. In EPA's analysis, combustion controls for NO_x are operated annually, even if they are only needed for summer season controls. Table A 5.2.1 provides combustion control technology unit costs and removal assumptions for Group 1 boilers (wall-fired and tangentially-fired units). Table A 5.2.2 provides combustion control unit costs and removal assumptions for Group 2 coal boilers (cell burners, cyclone, wet bottom, and vertically fired units).

TABLE A 5.2.1
NO_x Combustion Controls for CAAA Title IV Group 1 Coal Boilers
(300 MW Size)
(1999 $)

Boiler Type	Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	Fraction of Removal
Dry Bottom Wall-Fired	Low NO_x Burner without Overfire Air (LNB without OFA)	17.26	0.26	0.05	Minimum of 0.249+0.3111*Base NO_x, or 0.675
	Low NO_x Burner with Overfire Air (LNB with OFA)	23.43	0.36	0.07	Minimum of 0.379+0.3111*Base NO_x, or 0.675
Tangentially-Fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	33.19	0.50	0.00	Minimum of 0.109+0.507*Base NO_x, or 0.473
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	35.66	0.54	0.00	Minimum of 0.159+0.507*Base NO_x, or 0.523
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	47.99	0.73	0.02	Minimum of 0.209+0.507*Base NO_x, or 0.573

Scaling Factor

$$\text{LNB without OFA \& LNB with OFA} = \left(\frac{\$\text{ for 300MW}}{\$\text{ for x MW)}}\right) = \left(\frac{300}{x}\right)^{0.691}$$

$$\text{LNC 1, LNC2 and LNC3} = \left(\frac{\$\text{ for 300MW}}{\$\text{ for x MW}}\right) = \left(\frac{300}{x}\right)^{0.624}$$

SOURCE: "Cost-Effectiveness of Low -NOx Burner Technology Applied to Phase I, Group 1 Boilers," Acurex Environmental Corporation, July 1996.

TABLE A 5.2.2
NO_x Combustion Controls for CAAA Title IV Group 2 Coal Boilers
(300 MW Size)
(1999 $)

Boiler Type	Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	Percent Removal
Cell Burners	Non Plug-In Combustion Controls	23.43	0.35	0.07	60%
Cyclone	Coal Reburning	72.66	1.10	0.26	50%
Wet Bottom	NO_x Combustion Controls	9.87	0.14	0.05	50%
Vertically Fired	NO_x Combustion Controls	11.10	0.17	0.05	40%

Scaling Factor

$$\text{Cell Burners} = \left(\frac{\$\text{ for }300\text{MW}}{\$\text{ for x MW}}\right) = \left(\frac{300}{x}\right)^{.315}$$

$$\text{Wet Bottom/Vertically Fired} = \left(\frac{\$\text{ for }300\text{MW}}{\$\text{ for x MW}}\right) = \left(\frac{300}{x}\right)^{.553}$$

$$\text{Cyclone} = \left(\frac{\$\text{ for }300\text{MW}}{\$\text{ for x MW}}\right) = \left(\frac{300}{x}\right)^{.388}$$

SOURCE: "Cost-Effectiveness of Low -NOx Burner Technology Applied to Phase I, Group 1 Boilers," Acurex Environmental Corporation, July 1996.

A 5.2.2 Development of Policy NO_X Rates

Assumptions in EPA Base Case 2000 include NO_x policy rates that are used in modeling scenarios with NO_x reduction requirements incremental to existing NO_x regulations. The EPA Base Case 2000 retains the NO_x policy rates developed for the EPA Winter 1998 Base Case.

For the NO_x control policy options, EPA assumes that NO_x combustion controls would be installed on many types of coal boilers as an initial pollution control step. EPA assumes combustion controls are on all tangentially-fired, wall-fired, cell burner, cyclone, wet-bottom and vertically-fired boilers above 25 MW. Therefore, the NO_x rates for these units are adjusted to reflect this assumption at the outset of NO_x control options analyses. Again, other coal-fired units (not listed above), oil/gas units, and units using waste fuels have policy NO_x rates that are the same as the baseline (base case) NO_x rates.

The methodology for calculating policy NO_x rates for the applicable group of coal-fired units depends on the current existence of NO_x control options as indicated by EPA data, the boiler configuration (including the appropriate NO_x group of the boiler), and the reported actual NO_x emission rates. For each boiler, the following steps occurred:

1. For any coal boiler larger than 25 MW, for which current EPA data indicates some kind of installed NO_x control technology, the most recent available actual NO_x emissions rate _[at the time of the EPA Winter 1998 Base Case]_ was used as the policy rate. (For a description of the data sets providing this information, see Appendix 4 "Baseline Air Emission Rates" in *Analyzing Electric Power Generation Under the CAAA* (U.S. EPA, Office of Air and Radiation, US EPA, March 1998).)

2. For the remaining boilers, where they are larger than 25 MW and there is no indication of

currently installed control technology, the next step in computing the policy NO_x rate is to develop a NO_x "PreRate," which is intended to represent the uncontrolled NO_x rate of the boiler. Since this step is only relevant for boilers that have indicated to EPA that they do not have any NO_x controls, the most recent actual rate that EPA has should be the uncontrolled NO_x rate. However, this may not always be the case. EPA believes the reason for this is that certain units could be under-reporting NO_x rates, or not reporting that they have controls on their units. Therefore, EPA decided to consider also earlier data that the Agency had used in analysis to support the Title IV rules. In an effort to be conservative about what combustion controls can accomplish, EPA initially assessed whether the most recent reported data on the units NO_x rate is less than ninety percent of EPA's estimated uncontrolled NO_x rate for Title IV rule support. If it is, the uncontrolled NO_x rate used for Title IV rule support is carried to the next step of the analysis, otherwise, the PreRate is equal to the most recent reported rate. This approach is conservative, and results in higher overall rates than if either data source was used exclusively.

3. The chosen NO_x PreRate is then compared to the cutoff rates shown in Table A 5.2.3. These cut-off rates are the average NO_x rate that EPA estimates will exist at different types of boilers when combustion controls are in place. If the PreRate falls at or below the cutoff rate, or if the boiler type is unknown or does not match the boiler types listed in Table A 5.2.3 (e.g. fluidized bed or stoker/spreader design), the PreRate is used as the policy NO_x rate without additional modification.

TABLE A 5.2.3
Cutoff NO_x Rates for Determining Application of Combustion Controls

Boiler Type	NO_x Rate (lbs. per MMBtu)
Wall-Fired Dry-Bottom Tangentially-Fired	0.36 0.34
Cell-Burners	0.57
Cyclones	0.62
Wet-Bottom	0.59
Vertically-Fired	0.68

4. If the PreRate is higher than the indicated cutoff rate, the next step is to calculate the percentage NO_x reduction that would be associated with the installation of NO_x combustion controls. This percentage varies by boiler category, as shown in Table A 5.2.4.

TABLE A 5.2.4
Percentage NO_x Reduction from Combustion Controls

Boiler Type	Percent Reduction	Technology Represented
Wall-Fired Dry-Bottom	Variable, up to 67.5%*	Low NO_x burner without overfire air
Tangentially-Fired	Variable, up to 47.3%*	Low NO_x coal-and-air nozzles with close-coupled overfire air
Cell-Burners	60%	Non-plug-in combustion controls
Cyclones	50%	Coal reburning
Wet-Bottom	50%	NO_x combustion controls
Vertically-Fired	40%	NO_x combustion controls
* Removal rate varies by initial NO_x rate. EPA used formula in Table A5-1 for NO_x combustion controls for LNB without OFA (wall) and LNC1 (tangential).		

5. Once the percentage reduction is determined, the policy NO_x rate after combustion controls is initially calculated as the NO_x PreRate multiplied by (1 - the percentage NO_x reduction resulting from combustion controls). To avoid unrealistically low estimates of post-control emissions rates, the initially calculated NO_x rate after combustion controls is compared to a “floor” level of 0.30 lbs. per MMBtu; the higher of the two rates is used as the policy NO_x rate.

Appendix 5.3 Activated Carbon Injection

A 5.3.1 Description of Acronyms for Existing Controls

Acronym	Description
ESP	Electro Static Precipitator - Cold Side
HESP	Electro Static Precipitator - Hot Side
ESP/O	Electro Static Precipitator - Other
FF	Fabric Filter
FGD	Flue Gas Desulfurization - Wet
DS	Flue Gas Desulfurization - Dry
SCR	Selective Catalytic Reduction
PMSCRUB	Particulate Matter Scrubber

A 5.3.2 Cost Equations for ACI applications

Table A 5.3.2 below provides a summary of the sorbent-feed concentration and cost components of ACI for 80% and 90% mercury removal efficiency. The capital and O&M cost components shown in the table below utilize the various cost components described in the text and equations that follow the table. For example, under capital cost (1) refers to spray cooling, (2) to sorbent injection and (3) to sorbent disposal. Thus, (1) + (2) + (3) represent the costs associated with spray cooling, sorbent injection and sorbent disposal.

Table A 5.3.2. Sorbent-Feed Concentration and Cost Components for 80% and 90% Mercury Removal Efficiency Using ACI

#	Coal Type	Existing Pollution Control Technology	Sulfur Grade: H-High; L-Low.	Sorbent-Feed 80%	Sorbent-Feed 90%	CAPITAL COST COMPONENTS	O&M COST COMPONENTS
1A	Bituminous	ESP	L	8.0	18.2	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
2A	Bituminous	ESP/O	L	8.0	18.2	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
3A	Bituminous	ESP+FF	L	4.6	10.6	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
4A	Bituminous	ESP+FGD	H	6.2	24.4	(2) + (3)	1+ 2b + 2c + 2e + 2f
5A	Bituminous	ESP+FGD+SCR	H			None	None
6A	Bituminous	ESP+SCR	L	8.0	18.2	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
7A	Bituminous	FF	L	8.0	18.2	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
8A	Bituminous	FF+DS	H	5.0	11.5	(2) + (3)	1+ 2b + 2c + 2e + 2f
9A	Bituminous	FF+FGD	H	6.2	24.4	(2) + (3)	1+ 2b + 2c + 2e + 2f
10A	Bituminous	HESP	L	4.6	10.6	(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
11A	Bituminous	HESP+FGD	H	2.0	7.6	(2) + (3) + (4)	1+ 2b + 2c + 2e + 2g
12A	Bituminous	HESP+SCR	L	4.6	10.6	(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
13A	Bituminous	PMSCRUB+FGD	H	6.2	24.4	(2) + (3)	1+ 2b + 2c + 2e + 2f
14A	Bituminous	PMSCRUB+FGD+SCR	H			None	None
1B	Bituminous	ESP	H	31.9	58	(2) + (3)	1+2b + 2c + 2e + 2f
2B	Bituminous	ESP/O	H	31.9	58	(2) + (3)	1+2b + 2c + 2e + 2f
3B	Bituminous	ESP+FF	H	15.0	33.5	(2) + (3)	1+ 2b + 2c + 2e + 2f
4B	Bituminous	ESP+FGD	L	0.9	4	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
5B	Bituminous	ESP+FGD+SCR	L			None	None
6B	Bituminous	ESP+SCR	H	31.9	58	(2) + (3)	1+2b + 2c + 2e + 2f
7B	Bituminous	FF	H	31.9	58	(2) + (3)	1+2b + 2c + 2e + 2f
8B	Bituminous	FF+DS	L	5.0	11.5	(2) + (3)	1+ 2b + 2c + 2e + 2f
9B	Bituminous	FF+FGD	L	6.2	24.4	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
10B	Bituminous	HESP	H	15.0	33.5	(2) + (3)	1+ 2b + 2c + 2e + 2g
11B	Bituminous	HESP+FGD	L	0.5	2.25	(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
12B	Bituminous	HESP+SCR	H	15.0	33.5	(2) + (3) + (4)	1+ 2b + 2c + 2e + 2g
13B	Bituminous	PMSCRUB+FGD	L	0.9	4	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
14B	Bituminous	PMSCRUB+FGD+SCR	L			None	None
15	Lignite	ESP	L	9.0	21.4	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
16	Lignite	ESP+FF	L	0.8	1.9	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
17	Lignite	ESP+FGD	L	5.9	15.2	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
18	Lignite	FF+DS	L	0.8	1.9	(2) + (3)	1+ 2b + 2c + 2e + 2f
19	Lignite	FF+FGD	L	0.1	1.3	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
20	Subbituminous	ESP	L	9.0	21.4	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
21	Subbituminous	ESP+DS	L	9.0	21.4	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
22	Subbituminous	ESP+FGD	L	5.9	15.2	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
23	Subbituminous	ESP+SCR	L	9.0	21.4	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
24	Subbituminous	FF	L	0.8	1.9	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
25	Subbituminous	FF+DS	L	0.8	1.9	(2) + (3)	1+ 2b + 2c + 2e + 2f
26	Subbituminous	FF+FGD	L	0.1	1.3	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
27	Subbituminous	HESP	L	0.2	0.4	(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
28	Subbituminous	HESP+FGD	L	0.1	0.3	(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
29	Subbituminous	HESP+SCR	L	0.2	0.4	(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
30	Subbituminous	PMSCRUB	L	9.0	21.4	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
31	Subbituminous	PMSCRUB+FGD	L	5.9	15.2	(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f

Cost Equations for ACI

(A.1) MERCURY CONTROL CAPITAL COST ESTIMATION

Assumptions:

All costs are in December 1999 Dollars

Capital Cost units are in $/kW
Bare Installed Retrofit Cost (BIRC) is provided for the following subsystems:

(1) Spray Cooling
(2) Sorbent Injection
(3) Sorbent Disposal
(4) New pulse-jet fabric filter (PJFF)

BIRC accounts for Process Equipment, Field Materials, Field Labor, and Indirect Field Costs

Total Control Capital Cost (TCCC) is calculated as follows:

TCCC = 1.3725 x BIRC

TCCC multiplier accounts for Engineering & Home Office Overhead/Fees, Process Contingency, Project Contingency and General Facilities.

BIRC Costing Algorithms:

(1) Spray Cooling System

Spray Cooling BIRC, $/kW = 6025 x ((GPM/215)^0.65) / MWe

Where,
GPM = Water Consumption, units = gallons/minute (GPM)
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

GPM is calculated as follows:

GPM = 4.345E-7 x (Flue Gas Flow Rate, Lb/hr) x (Gas Temperature Change, F)

Flue Gas Flow Rate, Lb/hr = 1000 x MWe x (Heat Rate, Btu/Kw-Hr) x (Gas Flow Factor, Lb gas/Lb coal) /(Coal HHV, Btu/Lb)
where,
Gas Flow Factor, Lb gas/Lb coal = 15 for Bituminous Coal
Gas Flow Factor, Lb gas/Lb coal = 9 for Subbituminous Coal
Gas Temperature Change, F = 40 for Low Sulfur Bituminous Coal and Subbituminous Coal
Gas Temperature Change, F = 0 for High Sulfur Bituminous Coal

(2) Sorbent Injection System

Sorbent Injection BIRC, $/kW = 30 x (Sorbent Feed Rate, Kg/hr)^0.65 / MWe

Where,

Sorbent Feed Rate, Kg/hr = 4.54E-4 x (Sorbent Concentration, Lb/MMacf) x (Gas Flow Factor, acf/Lb coal) x (Heat Rate, Btu/kW-Hr) x MWe / (Coal HHV, Btu/Lb)

Sorbent Concentration, Lb/Mmacf = values specified in Table A. 5.3.2 above.

Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling

(3) Sorbent Disposal System

Sorbent Disposal BIRC, $/kW = 0.2 x (Sorbent Feed Rate, Kg/hr) / MWe

Sorbent Feed Rate, Kg/hr = same as previous calculation provided in (2) Sorbent Injection System

(4) New Pulse-Jet Fabric Filter System

PJFF BIRC, $/kW = 0.17 x (Flue Gas Volumetric Flow, ACFM)^0.8 / MWe

Where,

Flue Gas Volumetric Flow, ACFM = 16.67 x (Heat Rate, Btu/Kw-Hr) x MWe x (Gas Flow Factor, acf/Lb coal) / (Coal HHV, Btu/Lb)

Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling

(A.2) MERCURY CONTROL O&M COST ESTIMATION

Assumptions:

All costs are in December 1999 Dollars
Fixed O&M costs are in $/kW-Yr
Variable O&M (i.e., Consumables) costs are in mills/kW-Hr

Fixed O&M cost account for operating labor and maintenance labor and materials and do not include cost of consumables. Variable O&M costs include consumables, i.e., the cost of water, sorbent-feed, sorbent disposal, and electricity costs.

(1) Fixed and Variable O&M Cost Estimation

Fixed O&M Cost, $/kW-Yr = [(296.25 / MWe) + (0.165 x Total BIRC)]

Where,

Total BIRC is the sum of the BIRCs calculated in A.1 above
MWe = Power plant net capacity, MW (e.g., 100)

(2) Variable O&M (i.e., Consumables only) Cost Estimation

(2a) Water

Annual Water Cost, mills/kW-Hr = 2.52E-2 x GPM / MWe

Where,

GPM = Water Consumption, units = gallons/minute (GPM)
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

GPM is calculated as follows (same calculations as provided in capital cost estimation sheet):

GPM = 4.345E-7 x (Flue Gas Flow Rate, Lb/hr) x (Gas Temperature Change, F)

Flue Gas Flow Rate, Lb/hr = 1000 x MWe x (Heat Rate, Btu/Kw-Hr) x (Gas Flow Factor, Lb gas/Lb coal) / (Coal HHV, Btu/Lb)

where,
Gas Flow Factor, Lb gas/Lb coal = 15 for Bituminous Coal
Gas Flow Factor, Lb gas/Lb coal = 9 for Subbituminous Coal
Gas Temperature Change, F = 40 for Low Sulfur Bituminous Coal and Subbituminous Coal
Gas Temperature Change, F = 0 for High Sulfur Bituminous Coal

(2b) Sorbent (Powdered Activated Carbon only)

Annual Sorbent Cost, mills/kW-Hr = (Sorbent Feed Rate, Kg/hr) / MWe

Where,

Sorbent Feed Rate, Kg/hr = 4.54E-4 x (Sorbent Concentration, Lb/MMacf) x (Gas Flow Factor, acf/Lb coal) x (Heat Rate, Btu/kW-Hr) x MWe / (Coal HHV, Btu/Lb)

Sorbent Concentration, Lb/Mmacf = values specified in Table A 5.3.2 above
Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

(2c) Sorbent Disposal

Annual Sorbent Disposal Cost, mills/kW-Hr = 0.033 x (Sorbent Feed Rate, Kg/hr) / MWe

Where,

Sorbent feed rate is the same value calculated in 2b
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

(2d) Power Cost for Water Injection

Water Injection Power Cost, mills/kW-Hr = 0.163 x GPM/ MWe

Where,

GPM = Water Consumption, units = gallons/minute (GPM)
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

GPM is the same value calculated in 2a

(2e) Power Cost for Sorbent Injection

Sorbent Injection Power Cost, mills/kW-Hr = 3.4E-3 x (Sorbent Feed Rate, Kg/hr) / MWe

Where,

Sorbent feed rate is the same value calculated in 2b
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

(2f) Incremental Fan Power without New PJFF

Fan Power Cost without New PJFF, mills/kW-Hr = 9.165E-7 x (Flue Gas Volumetric Flow, ACFM) / MWe

Where,

Flue Gas Volumetric Flow, ACFM = 16.67 x (Heat Rate, Btu/Kw-Hr) x MWe x (Gas Flow Factor, acf/Lb coal) / (Coal HHV, Btu/Lb)

Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

(2g) Incremental Fan Power with New PJFF

Fan Power Cost with New PJFF, mills/kW-Hr = 2.29E-5 x (Flue Gas Volumetric Flow, ACFM) / MWe

-

Where,

Flue Gas Volumetric Flow, ACFM = 16.67 x (Heat Rate, Btu/Kw-Hr) x MWe x (Gas Flow Factor, acf/Lb coal) / (Coal HHV, Btu/Lb)

Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

Appendix 5.4 Emission Modification Factors based on EIA Mercury Removal Assumptions

The following table shows alternative EMFs developed for a sensitivity analysis based on the U.S. Department of Energy, Energy Information Administration's mercury removal assumptions. For EMFs that differ from those used in EPA Base Case 2000, the EMF value based on EIA assumptions is shown first, followed in parentheses by the EMF value used in EPA Base Case 2000. EMF values that are the same as in EPA Base Case 2000 are highlighted in gray.

Table A5.4.1. Alternative Emission Modification Factors Based on EIA Mercury Removal Assumptions

Burner Type	Particulate Control	Post Combustion Control -- NO_x	Post Combustion Control -- SO_2	Bituminous EMF	Sub-bituminous EMF
Cyclone	Cold side ESP	None	None	0.6	0.85
Cyclone	Cold side ESP	SCR	None	0.6	0.85
Cyclone	Cold side ESP	SNCR/Other	None	0.6	0.85
Cyclone	Cold side ESP	None	Wet FGD	0.45	0.6
Cyclone	Cold side ESP	SCR	Wet FGD	0.14 (0.05)	0.34 (0.05)
Cyclone	Cold side ESP	SNCR	Wet FGD	0.1	0.6 (0.1)
Cyclone	Hot side ESP	None	None	0.9	1
Cyclone	Hot side ESP	SCR	None	0.9	1
Cyclone	Hot side ESP	SNCR/Other	None	0.9	1
Cyclone	Hot side ESP	None	Wet FGD	0.45	0.6
Cyclone	Fabric Filter	None	None	0.45	0.95
Cyclone	Fabric Filter	SCR	None	0.45	0.95
Cyclone	Fabric Filter	SNCR/Other	None	0.45	0.95
Cyclone	Fabric Filter	None	Wet FGD	0.4	0.95
Cyclone	Fabric Filter	None	Dry FGD	0.4	0.95
Cyclone	Fabric Filter	SCR	Wet FGD	0.06 (0.05)	0.15 (0.05)
Cyclone	Fabric Filter	SCR	Dry FGD	0.45	0.95
Cyclone	Fabric Filter	SNCR	Wet FGD	0.1	0.95 (0.1)
Cyclone	Fabric Filter	SNCR	Dry FGD	0.4	0.95
Cyclone	PM Scrubber	None	None	0.8	1
Cyclone	No Control	None	None	1	1
Cyclone	No Control	SCR	None	1	1
Cyclone	No Control	SNCR/Other	None	1	1
Cyclone	No Control	None	Wet FGD	0.45	0.6
Cyclone	No Control	SCR	Wet FGD	0.21 (0.05)	0.49 (0.05)
Cyclone	No Control	SNCR	Wet FGD	0.32 (0.1)	0.75 (0.1)
PC	Cold side ESP	None	None	0.6	0.85
PC	Cold side ESP	SCR	None	0.6	0.85
PC	Cold side ESP	SNCR/Other	None	0.6	0.85
PC	Cold side ESP	None	Wet FGD	0.2	0.65
PC	Cold side ESP	None	Dry FGD	0.6	0.85
PC	Cold side ESP	SCR	Wet FGD	0.14 (0.05)	0.34 (0.05)
PC	Cold side ESP	SNCR	Wet FGD	0.1	0.65 (0.1)
PC	Cold side ESP	SNCR	Dry FGD	0.6	0.85
PC	Hot side ESP	None	None	0.9	0.9
PC	Hot side ESP	SCR	None	0.9	0.9
PC	Hot side ESP	SNCR/Other	None	0.9	0.9
PC	Hot side ESP	None	Wet FGD	0.45	0.7
PC	Hot side ESP	None	Dry FGD	0.6	0.85
PC	Hot side ESP	SCR	Wet FGD	0.32 (0.05)	0.75 (0.05)
PC	Hot side ESP	SCR	Dry FGD	0.6	0.85
PC	Hot side ESP	SNCR	Wet FGD	0.32 (0.1)	0.75 (0.1)
PC	Hot side ESP	SNCR	Dry FGD	0.6	0.85
PC	Fabric Filter	None	None	0.4	0.75
PC	Fabric Filter	SCR	None	0.4	0.75
PC	Fabric Filter	SNCR/Other	None	0.4	0.75
PC	Fabric Filter	None	Wet FGD	0.05	0.3
PC	Fabric Filter	None	Dry FGD	0.05	0.75
PC	Fabric Filter	SCR	Wet FGD	0.06 (0.05)	0.15 (0.05)
PC	Fabric Filter	SCR	Dry FGD	0.05	0.75
PC	Fabric Filter	SNCR	Wet FGD	0.1	0.3 (0.1)
PC	Fabric Filter	SNCR	Dry FGD	0.05	0.75

Notes:
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Burner Type	Particulate Control	Post Combustion Control -- NO_x	Post Combustion Control -- SO_2	Bituminous EMF	Sub-bituminous EMF
PC	Cold side ESP + FF	None	None	0.2	0.75
PC	Cold side ESP + FF	SCR	None	0.2	0.75
PC	Cold side ESP + FF	SNCR/Other	None	0.2	0.75
PC	Cold side ESP + FF	None	Wet FGD	0.05	0.3
PC	Hot side ESP + FF	None	Wet FGD	0.05	0.3
PC	Hot side ESP + FF	None	Dry FGD	0.05	0.75
PC	Hot side ESP + FF	SCR	Wet FGD	0.06 (0.05)	0.15 (0.05)
PC	Hot side ESP + FF	SCR	Dry FGD	0.05	0.75
PC	Hot side ESP + FF	SNCR	Wet FGD	0.05	0.3 (0.1)
PC	Hot side ESP + FF	SNCR	Dry FGD	0.05	0.75
PC	PM Scrubber	None	None	0.9	1
PC	PM Scrubber	SCR	None	0.9	1
PC	No Control	None	None	1	1
PC	No Control	SCR	None	1	1
PC	No Control	SNCR/Other	None	1	1
PC	No Control	None	Wet FGD	0.45	0.7
PC	No Control	None	Dry FGD	0.6	0.85
PC	No Control	SCR	Wet FGD	0.21 (0.05)	0.49 (0.05)
PC	No Control	SCR	Dry FGD	0.45	0.7
PC	No Control	SNCR	Wet FGD	0.32 (0.1)	0.75 (0.1)
PC	No Control	SNCR	Dry FGD	0.6	0.85
FBC	Cold side ESP	None	None	0.65	0.65
FBC	Cold side ESP	None	Wet FGD	0.65	0.65
FBC	Cold side ESP	SCR	Wet FGD	0.14 (0.05)	0.34 (0.05)
FBC	Cold side ESP	SNCR	Wet FGD	0.14 (0.1)	0.65 (0.1)
FBC	Fabric Filter	None	None	0.45	0.45
FBC	Fabric Filter	SCR	None	0.25	0.45
FBC	Fabric Filter	None	Wet FGD	0.45	0.45
FBC	Fabric Filter	SCR	Wet FGD	0.06 (0.05)	0.15 (0.05)
FBC	Fabric Filter	SNCR	Wet FGD	0.1	0.45 (0.1)
FBC	No Control	None	None	1	1
FBC	No Control	SCR	None	1	1
FBC	No Control	SNCR/Other	None	1	1
FBC	No Control	None	Wet FGD	1	1
FBC	No Control	None	Dry FGD	0.45	0.45
FBC	No Control	SCR	Wet FGD	0.21 (0.05)	0.49 (0.05)
FBC	No Control	SNCR	Dry FGD	0.45	0.45
Stoker	Cold side ESP	None	None	0.65	0.85
Stoker	Cold side ESP	SCR	None	0.65	0.65
Stoker	Cold side ESP	SNCR/Other	None	0.65	0.65
Stoker	Cold side ESP	None	Wet FGD	0.6	0.65
Stoker	Hot side ESP	None	None	1	1
Stoker	Hot side ESP	SCR	None	1	1
Stoker	Hot side ESP	SNCR/Other	None	1	1
Stoker	Hot side ESP	None	Wet FGD	1	1
Stoker	Fabric Filter	None	None	0.1	0.45
Stoker	Fabric Filter	SCR	None	0.1	0.45
Stoker	Fabric Filter	SNCR/Other	None	0.1	0.45
Stoker	Fabric Filter	None	Wet FGD	0.1	0.45
Stoker	Fabric Filter	None	Dry FGD	0.1	0.45
Stoker	No Control	None	None	1	1
Stoker	No Control	SCR	None	1	1

Notes:

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Burner Type	Particulate Control	Post Combustion Control -- NO_x	Post Combustion Control -- SO_2	Bituminous EMF	Sub-bituminous EMF
Stoker	No Control	SNCR/Other	None	1	1
Stoker	No Control	None	Wet FGD	1	1
Other	Cold side ESP	None	None	0.6	0.85
Other	Cold side ESP	SCR	None	0.6	0.85
Other	Cold side ESP	SNCR/Other	None	0.6	0.85
Other	Cold side ESP	None	Wet FGD	0.6	0.85
Other	Hot side ESP	None	None	1	1
Other	Hot side ESP	SCR	None	1	1
Other	Hot side ESP	SNCR/Other	None	1	1
Other	Hot side ESP	None	Wet FGD	1	1
Other	Fabric Filter	None	None	0.45	0.95
Other	Fabric Filter	SCR	None	0.45	0.95
Other	Fabric Filter	None	Wet FGD	0.4	0.95
Other	Fabric Filter	None	Dry FGD	0.4	0.95
Other	Fabric Filter	SCR	Wet FGD	0.06 (0.05)	0.15 (0.05)
Other	Fabric Filter	SCR	Dry FGD	0.4	0.95
Other	Fabric Filter	SNCR	Wet FGD	0.10	0.95 (0.1)
Other	Fabric Filter	SNCR	Dry FGD	0.4	0.95
Other	No Control	None	None	1	1
Other	No Control	SCR	None	1	1
Other	No Control	SNCR/Other	None	1	1
Other	No Control	None	Wet FGD	1	1
Other	No Control	SCR	Wet FGD	0.21 (0.05)	0.49 (0.05)
Other	No Control	SNCR	Wet FGD	0.32 (0.1)	0.75 (0.1)
Cyclone	No Control	None	None	1	1
FBC	No Control	None	None	1	1
PC	No Control	None	None	1	1
PC	No Control	None	Wet FGD	0.45	0.7
PC	No Control	SNCR/Other	None	1	1
PC	Cold side ESP	None	Dry FGD	0.55	0.85
PC	Cold side ESP + FF	SCR	Wet FGD	0.05	0.3 (0.05)
PC	Cold side ESP + FF	SNCR	Wet FGD	0.1	0.3 (0.1)
Cyclone	No Control	None	Dry FGD	1	1
Cyclone	Cold side ESP	None	Dry FGD	0.6	0.85
Cyclone	Cold side ESP	SCR	Dry FGD	0.6	0.85
Cyclone	Hot side ESP	None	Dry FGD	0.9	1
Other	No Control	None	Dry FGD	1	1
Other	Cold side ESP	None	Dry FGD	0.6	0.85
Other	Hot side ESP	None	Dry FGD	1	1
PC	Cold side ESP	SCR	Dry FGD	0.6	0.85
PC	Cold side ESP + FF	None	Dry FGD	0.05	0.75
Stoker	No Control	None	Dry FGD	1	1
Stoker	Cold side ESP	None	Dry FGD	0.65	0.85
Stoker	Hot side ESP	None	Dry FGD	1	1
Cyclone	Hot side ESP	SCR	Dry FGD	0.9	1
Cyclone	No Control	SCR	Dry FGD	1	1
PC	Cold side ESP + FF	SCR	Dry FGD	0.05	0.75
FBC	No Control	SCR	Dry FGD	0.45	0.45
Stoker	Cold side ESP	SCR	Dry FGD	0.65	0.85
Stoker	Hot side ESP	SCR	Dry FGD	1	1
Stoker	Fabric Filter	SCR	Dry FGD	0.1	0.45
Stoker	No Control	SCR	Dry FGD	1	1

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