Appendix E. Four-Factor Analyses - MPCA Cost Revisions

This appendix contains the revisions the MPCA made to the cost estimates provided by facilities in response to MPCA's request to prepare a four-factor analysis for specifically identified emission units. To evaluate the cost of compliance, the MPCA requested that each facility prepare cost estimates for the potential control measures evaluated in the four-factor analysis.

The MPCA reviewed the emissions data provided in each four-factor analysis and compared that information to the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020. Where emissions data used by facilities did not match the baseline emissions as calculated in the Control Cost Manual cost estimation spreadsheets, the MPCA revised the emissions data used as part of evaluating potential control measures.[1]

U.S. EPA provides recommendations in its August 2019 Guidance on determining the costs of identified control measures.[2] U.S. EPA's recommendations generally suggest that states follow the methodologies and recommendations in the U.S. EPA Air Pollution Control Cost Manual and use the cost calculation spreadsheets where available for the type of emission control system.[3] U.S. EPA also points to the use of these resources as a way to compare different control options for the same source and comparisons across different sources. This also provides consistency for informed public comment and decision-making while allowing states to rely on a simple reference to the Control Cost Manual as documentation of, and rationale for, the approach.

In the four-factor analysis request to facilities, and in subsequent conversations, the MPCA recommended that facilities prepare cost estimates by following the recommendations identified in U.S. EPA's August 2019 Guidance and use the cost estimation spreadsheets where available for the type of control measure.[4] In general, facilities provided cost estimates that followed the recommendations in the Control Cost Manual and used the cost estimation spreadsheets when available. The MPCA reviewed the cost estimates that facilities provided, including the comments provided by FLMs, U.S. EPA, or Tribes, and revised the cost estimates prepared to address certain parameters in those estimates (e.g., interest rate, retrofit factors, etc.).

This appendix contains revised cost estimates for the following facilities:

- American Crystal Sugar - Crookston
- American Crystal Sugar - East Grand Forks
- Boise White Paper
- Hibbing Public Utilities Commission
- Northshore Mining Company
- Sappi Cloquet
- Southern Minnesota Beet Sugar Cooperative
- Virginia Department of Public Utilities

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[1] *See* U.S. EPA, Cost Reports and Guidance for Air Pollution Regulations, *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution* (last visited June 23, 2022) [hereinafter Cost Reports and Guidance for Air Pollution Regulations].

[2] *See* U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period 55 (Aug. 2019), *https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf* [hereinafter Aug. 2019 EPA Guidance], at 31-32.

[3] *See* U.S. EPA, Cost Reports and Guidance for Air Pollution Regulations*, supra.*

[4] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 31-32; U.S. EPA, Cost Reports and Guidance for Air Pollution Regulations*, supra.*

Data Inputs (MPCA FFA Costs, American Crystal Sugar - Crookston, Boiler 1&2, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 137 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 9,400 Btu/lb

What is the estimated actual annual fuel consumption? 74,154,894 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.38 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 4.12 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	265	days	Plant Elevation	840	Feet above sea level
Number of days the boiler operates (t_{plant})	265	days			
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.33	lb/MMBtu			
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.25	lb/MMBtu			
Estimated Normalized Stoichiometric Ratio (NSR)	1.05				

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Select the reagent used: Ammonia

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	1.9	$/MMBtu		
Reagent ($Cost_{reag}$)	0.554	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	137	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	127,672,340	lbs/Year	
Actual Annual fuel consumption (Mactual) =		74,154,894	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.581	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5088	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	24	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	10.96	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	27.88	tons/year	115.01424
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at 840 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	61	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	8.1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	2,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	2.2	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	14	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x $((1/C_{inj})-1)$ =	0.14	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	0.6	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,201,809 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,701,860 in 2019 dollars
Total Capital Investment (TCI) =	\$3,774,769 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,201,809 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$1,701,860 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$82,122	in 2019 dollars
Indirect Annual Costs (IDAC) =	$267,442	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$349,565	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$56,622	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$22,797	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$958	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$293	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,376	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$77	in 2019 dollars
Direct Annual Cost =		$82,122	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,699	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$265,744	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$267,442	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$349,565	per year in 2019 dollars
NOx Removed =	28	tons/year
Cost Effectiveness =	$12,537	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, American Crystal Sugar - Crookston, Boiler 1&2, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 137 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 9,400 Btu/lb

What is the estimated actual annual fuel consumption? 74,154,894 lbs/Year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 840 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.38 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ◉ Method 1
- ○ Method 2
- ○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	265	days
Number of days the boiler operates (t_{plant})	265	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.33	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.07	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	100200	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	400	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	731	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI
Annual Interest Rate (i)	3.5	Percent
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0844	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	137	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	127,672,340	lbs/Year	
Actual Annual fuel consumption (Mactual) =		74,154,894	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.581	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5088	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	78.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	35.62	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	90.62	tons/year	115.01424
NO_x removal factor (NRF) =	EF/80 =	0.98		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	100,200	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	55.64	/hour	
Residence Time	$1/V_{space}$	0.02	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.2373	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,800.88	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	104	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	7	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	120	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	11.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	64	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	14	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	48	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	78.35	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$6,224,628	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,317,828	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$2,809,173	in 2019 dollars
Total Capital Investment (TCI) =	$14,757,119	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$6,224,628 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,317,828 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,809,173 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$157,727	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,041,695	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,199,421	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$73,786	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$17,961	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$33,644	in 2019 dollars
Annual Catalyst Replacement Cost =		$32,336	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$157,727	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,793	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,038,901	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,041,695	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,199,421	per year in 2019 dollars
NOx Removed =	91	tons/year
Cost Effectiveness =	$13,236	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, American Crystal Sugar - Crookston, Boiler 3, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 165 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 9,400 Btu/lb

What is the estimated actual annual fuel consumption? 89,310,638 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.38 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 4.12 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	265	days
Number of days the boiler operates (t_{plant})	265	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.32	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.288	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

Plant Elevation	840	Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	1.9	\$/MMBtu		
Reagent ($Cost_{reag}$)	0.554	\$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	\$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	\$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	\$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

Data Inputs (MPCA FFA Costs, American Crystal Sugar - Crookston, Boiler 3, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	165	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	153,765,957	lbs/Year
Actual Annual fuel consumption (Mactual) =		89,310,638	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.581	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5088	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	10	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	5.28	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	13.43	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at 840 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	21	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	71	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	9.5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	3,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	2.6	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	16	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.17	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	0.7	lb/hour

ta Inputs (MPCA FFA Costs, American Crystal Sugar - Crookston, Boiler 3, SNCR, 2022-05-

Enter the following data for your combustion unit:

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,299,439 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,657,733 in 2019 dollars
Total Capital Investment (TCI) =	$3,844,323 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,299,439 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,657,733 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$87,447	in 2019 dollars
Indirect Annual Costs (IDAC) =	$272,370	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$359,817	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$57,665	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$26,624	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,119	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$342	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,607	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$90	in 2019 dollars
Direct Annual Cost =		$87,447	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,730	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$270,640	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$272,370	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$359,817	per year in 2019 dollars
NOx Removed =	13	tons/year
Cost Effectiveness =	$26,787	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, American Crystal Sugar - Crookston, Boiler 3, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 165 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 9,400 Btu/lb

What is the estimated actual annual fuel consumption? 89,310,638 lbs/Year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 840 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.38 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	265	days
Number of days the boiler operates (t_{plant})	265	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.32	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.06	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	103000	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	460	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	624	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI
Annual Interest Rate (i)	3.5	Percent
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0844	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	165	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	153,765,957	lbs/Year	
Actual Annual fuel consumption (Mactual) =		89,310,638	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.581	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5088	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	81.3	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	42.90	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	109.14	tons/year	134.3232
NO_x removal factor (NRF) =	EF/80 =	1.02		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	103,000	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	62.07	/hour	
Residence Time	$1/V_{space}$	0.02	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.3	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.2373	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,659.32	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	107	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	6	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	123	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	11.1	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	62	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	17	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	57	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,600	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	94.36	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$7,431,706	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,428,131	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$3,037,380	in 2019 dollars
Total Capital Investment (TCI) =	$16,766,382	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$7,431,706	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,428,131	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,037,380	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$175,778	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,183,267	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,359,046	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$83,832	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$21,632	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$40,520	in 2019 dollars
Annual Catalyst Replacement Cost =		$29,794	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$175,778	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,914	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,180,353	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,183,267	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,359,046	per year in 2019 dollars
NOx Removed =	109	tons/year
Cost Effectiveness =	$12,453	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, American Crystal Sugar - East Grand Forks, Boiler 1&2, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 356 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 9,400 Btu/lb

What is the estimated actual annual fuel consumption? 210,661,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.38 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 4.12 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	265	days
Number of days the boiler operates (t_{plant})	265	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.34	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.306	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

Plant Elevation | 840 | Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI
Annual Interest Rate (i)	3.5	Percent
Fuel ($Cost_{fuel}$)	1.9	\$/MMBtu
Reagent ($Cost_{reag}$)	0.554	\$/gallon for a 29 percent solution of ammonia
Water ($Cost_{water}$)	0.0042	\$/gallon*
Electricity ($Cost_{elect}$)	0.0844	\$/kWh
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	\$/ton*

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	356	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	331,761,702	lbs/Year	
Actual Annual fuel consumption (Mactual) =		210,661,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.635	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5562	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	10	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	12.64	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	35.15	tons/year	338.12144
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at 840 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	47	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	163	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	21.8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	7,400	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	6.0	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	37	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.38	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	1.7	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,794,823 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	\$2,372,513 in 2019 dollars
Total Capital Investment (TCI) =	\$5,417,537 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,794,823 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$2,372,513 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$156,231	in 2019 dollars
Indirect Annual Costs (IDAC) =	$383,833	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$540,063	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$81,263	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$67,018	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$2,817	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$860	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$4,045	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$228	in 2019 dollars
Direct Annual Cost =		$156,231	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,438	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$381,395	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$383,833	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$540,063	per year in 2019 dollars
NOx Removed =	35	tons/year
Cost Effectiveness =	$15,365	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, American Crystal Sugar - East Grand Forks, Boiler 1&2, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 356 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 9,400 Btu/lb

What is the estimated actual annual fuel consumption? 210,661,000 lbs/Year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 840 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.38 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	265	days
Number of days the boiler operates (t_{plant})	265	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.34	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.07	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	210000	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	450	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	590	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	356	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	331,761,702	lbs/Year	
Actual Annual fuel consumption (Mactual) =		210,661,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.635	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5562	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	79.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	96.65	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	268.81	tons/year	338.12144
NO_x removal factor (NRF) =	EF/80 =	0.99		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	210,000	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	56.34	/hour	
Residence Time	$1/V_{space}$	0.02	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.2373	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,727.67	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	219	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	7	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	252	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	15.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	64	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	38	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	130	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	17	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	203.59	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$15,012,341	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,974,834	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$4,195,318	in 2019 dollars
Total Capital Investment (TCI) =	$28,837,241	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$15,012,341	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,974,834	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$4,195,318	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$359,977	in 2019 dollars
Indirect Annual Costs (IDAC) =	$2,033,780	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,393,757	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$144,186	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$53,281	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$95,577	in 2019 dollars
Annual Catalyst Replacement Cost =		$66,933	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$359,977	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,638	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,030,142	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,033,780	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,393,757	per year in 2019 dollars
NOx Removed =	269	tons/year
Cost Effectiveness =	$8,905	per ton of NOx removed in 2019 dollars

EGF Dry FGD Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	5,342,587	Scaled Quote
Control/Instrumentation[C]	534,300	10% of Equipment Cost
Sales Tax	320,600	6% of Equipment Cost
Freight[C]	267,100	5% of Equipment Cost
Total Equipment Cost (TEC)	**6,464,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	5,494,900	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	245,600	Estimated by HDR
Exhaust Stack	97,300	Estimated by HDR
Retrofit Interconnection/Ductwork	324,000	Estimated by HDR
Total Direct Investment (TDI)	12,626,400	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	193,900	3% of TEC
Engineering	646,500	10% of TEC
Construction & Field Expense	646,500	10% of TEC
Contractor Fees	646,500	10% of TEC
Start-up Assistance	64,600	1% of TEC
Performance Test	64,600	1% of TEC
Total Indirect Investment (TII)	**2,262,600**	

Total Turnkey Cost (TTC)	**14,889,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

EGF Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Fabric Filter Equipment[B]	4,645,728	Scaled Quote
Control/Instrumentation[C]	464,600	10% of Equipment Cost
Sales Tax	278,700	6% of Equipment Cost
Freight[C]	232,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**5,621,300**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	4,159,800	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	-	Included in SDA Costs
Exhaust Stack	-	Included in SDA Costs
Retrofit Cost Addition	-	Included in SDA Costs
Total Direct Investment (TDI)	9,781,100	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	168,600	3% of TEC
Engineering	562,100	10% of TEC
Construction & Field Expense	1,124,300	20% of TEC
Contractor Fees	562,100	10% of TEC
Start-up Assistance	56,200	1% of TEC
Performance Test	56,200	1% of TEC
Total Indirect Investment (TII)	**2,529,500**	

Total Turnkey Cost (TTC)	**12,310,600**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

EGF Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	457,900	Consumption x cost
Fabric Filter Bag Replacement	304,900	Labor plus bag cost
Solids Scrubber Disposal	100,300	Production x cost
Solids Fly Ash Disposal	168,000	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	231,100	Consumption x cost
Pump	76,700	Consumption x cost
Direct Annual Costs (DAC)	**1,701,200**	

Indirect Annual Costs [C]		
Overhead	675,100	60% of O&M Labor
Administrative Charges	544,000	2% of Total Capital Investment
Property Taxes	272,000	1% of Total Capital Investment
Insurance	272,000	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	1,194,700	(Capital Investment) x (CFR of 0.08024)
Fabric Filter Annualized Costs[D]	987,800	(Capital Investment) x (CFR of 0.08024)
Indirect Annual Costs (IAC)	**3,945,600**	

Total Annualized Costs (TAC)	**5,646,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Interest Rate Comparison

675,100
544,000
272,000
272,000
1,047,578
866,157
3,676,835

5,378,000

$$CRF = i(1+i)^n / ((1+i)^n-1)$$

Interest (i)	5%	3.5%
Life (n)	20	20
CRF	0.08024	0.07036

EGF Dry Sorbent Injection Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
DSI Equipment[B]	1,490,000	Vendor Quote
Control/Instrumentation[C]	149,000	10% of Equipment Cost
Sales Tax	89,400	6% of Equipment Cost
Freight[C]	74,500	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,802,900**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,532,500	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Flatwork/Drainage/Retrofit[D]	52,000	Estimated HDR
Total Direct Investment (TDI)	3,387,400	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	180,300	10% of TEC (Retrofit Adjustment, HDR)
Engineering	90,100	5% of TEC
Construction & Field Expense	180,300	10% of TEC
Contractor Fees	180,300	10% of TEC
Start-up Assistance	18,000	1% of TEC
Performance Test	36,100	2% of TEC (Adjusted, HDR)
Total Indirect Investment (TII)	**685,100**	

Total Turnkey Cost (TTC)	**4,072,500**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

EGF Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	55,000	Consumption x cost
Solids Fly Ash Disposal	27,000	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	23,000	Consumption x cost
Direct Annual Costs (DAC)	**182,500**	
Indirect Annual Costs [C]		
Overhead	79,500	60% of O&M Labor
Administrative Charges	81,500	2% of Total Capital Investment
Property Taxes	40,700	1% of Total Capital Investment
Insurance	40,700	1% of Total Capital Investment
DSI Annualized Costs[D]	334,100	(Capital Investment) x (CFR of 0.08024)
Indirect Annual Costs (IAC)	**576,500**	
Total Annualized Costs (TAC)	**759,000**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Interest Rate Comparison

79,500
81,500
40,700
40,700
292,957
535,357

717,900

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$

Interest (i)	5%	3.5%
Life (n)	20	20
CRF	0.08024	0.07036

EGF Dry Sorbent Injection Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
DSI Equipment[B]	1,498,000	Vendor Quote
Control/Instrumentation[C]	149,800	10% of Equipment Cost
Sales Tax	89,900	6% of Equipment Cost
Freight[C]	74,900	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,812,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,540,700	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Total Direct Investment (TDI)	3,353,300	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	181,300	10% of TEC (Retrofit Adjustment, HDR)
Engineering	181,300	10% of TEC
Construction & Field Expense	181,300	10% of TEC
CFD Modeling	70,000	Vendor Quote
Contractor Fees	181,300	10% of TEC
Start-up Assistance	18,100	1% of TEC
Performance Test	36,300	2% of TEC (Adjusted, HDR)
Total Indirect Investment (TII)	**849,600**	

Total Turnkey Cost (TTC)	**4,202,900**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, UCC, 2021.

DSI silo

Unloading Station

Mill and Compressor

No erection or installation

No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

EGF DSI Fabric Filter Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Fabric Filter Equipment[B]	11,816,600	Scaled Quote (Two Baghouses)
Control/Instrumentation[C]	1,181,700	10% of Equipment Cost
Sales Tax	709,000	6% of Equipment Cost
Freight[C]	590,800	5% of Equipment Cost
Total Equipment Cost (TEC)	**14,298,100**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	10,580,600	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Demolition of ESPs[D]	200,000	Demolition and Site Prep
Stack Replacement[D]	912,700	Extend two stacks to 200'
Total Direct Investment (TDI)	25,991,400	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	428,900	3% of TEC
Engineering	1,429,800	10% of TEC
Construction & Field Expense	2,859,600	20% of TEC
Contractor Fees	1,429,800	10% of TEC
Start-up Assistance	143,000	1% of TEC
Performance Test	143,000	1% of TEC
Total Indirect Investment (TII)	**6,434,100**	

Total Turnkey Cost (TTC)	**32,425,500**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled for capacity.
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Hammon Research-Cottrell, 2021
Pulse Jet Fabric Filter Baghouse
120 ft exhaust stack
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual,
Sixth Edition, January 2002, for fabric filters.

[D] Estimated by HDR.

EGF Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
DSI Labor	49,200	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	7,400	15% of labor
Fabric Filter Labor	194,400	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	29,200	15% of labor
Solvent (Trona)	1,801,200	Consumption x cost
Fabric Filter Bag Replacement	304,900	Labor plus bag cost
Solids Fly Ash Disposal	168,000	Production x cost
Maintenance Labor, Fabric F.	49,200	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	49,200	100% of labor
Maintenance Labor, DSI	49,200	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, DSI	49,200	100% of labor
DSI Electric Demand	36,400	606,435 kW/yr
Fabric F. Electrical Demand	61,600	513,500 kW/yr/unit
Direct Annual Costs (DAC)	**2,849,100**	

Indirect Annual Costs [C]		
Overhead	227,200	60% of O&M Labor
Administrative Charges	732,600	2% of Total Capital Investment
Property Taxes	366,300	1% of Total Capital Investment
Insurance	366,300	1% of Total Capital Investment
DSI Annualized Costs[D]	344,800	(Capital Investment) x (CFR of 0.08024)
Fabric Filter Annualized Costs[D]	2,660,200	(Capital Investment) x (CFR of 0.08024)
Indirect Annual Costs (IAC)	**4,697,400**	

Total Annualized Costs (TAC)	**7,546,500**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interest rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

From American Crystal Sugar SO2 Supplement (2022-02-02):

Table 1 – EGF SO_2 Cost of Compliance

Description	DSI
Emission Rate (lb/MMBtu)	0.14
Emission Reduction (tpy)	633
Capital Cost ($)	36,628,400
Direct Annual Cost ($)	2,849,100
Indirect Annual Cost ($)	4,697,400
Total Annualized Cost ($)	7,546,500
Cost Effectiveness ($/ton)	11,900

Interest Rate Comparison

227,200
732,600
366,300
366,300
295,700
2,281,500
4,269,600
7,118,700

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$

Interest (i)	5%	3.5%
Life (n)	20	20
CRF	0.08024	0.07036

Emission Reduction (tpy)	633
Cost Effectivness ($/ton)	11,200

CRK No. 1 Dry FGD Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	3,014,251	Scaled Quote
Control/Instrumentation[C]	301,400	10% of Equipment Cost
Sales Tax	180,900	6% of Equipment Cost
Freight[C]	150,700	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,647,300**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	3,100,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	138,500	Estimated by HDR
Exhaust Stack	97,300	Estimated by HDR
Retrofit Cost Addition	182,700	Estimated by HDR
Total Direct Investment (TDI)	7,166,000	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	109,400	3% of TEC
Engineering	364,700	10% of TEC
Construction & Field Expense	364,700	10% of TEC
Contractor Fees	364,700	10% of TEC
Start-up Assistance	36,500	1% of TEC
Performance Test	36,500	1% of TEC
Total Indirect Investment (TII)	**1,276,500**	
Total Turnkey Cost (TTC)	**8,442,500**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual,
Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 1 Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Fabric Filter Equipment[B]	2,621,088	Scaled Quote
Control/Instrumentation[C]	262,100	10% of Equipment Cost
Sales Tax	157,300	6% of Equipment Cost
Freight[C]	131,100	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,171,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	2,347,000	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	-	Included in SDA Costs
Exhaust Stack	-	Included in SDA Costs
Retrofit Cost Addition	-	Included in SDA Costs
Total Direct Investment (TDI)	5,518,600	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	95,100	3% of TEC
Engineering	317,200	10% of TEC
Construction & Field Expense	634,300	20% of TEC
Contractor Fees	317,200	10% of TEC
Start-up Assistance	31,700	1% of TEC
Performance Test	31,700	1% of TEC
Total Indirect Investment (TII)	**1,427,200**	

Total Turnkey Cost (TTC)	**6,945,800**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 1 Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	256,400	Consumption x cost
Fabric Filter Bag Replacement	170,700	Labor plus bag cost
Solids Scrubber Disposal	56,200	Production x cost
Solids Fly Ash Disposal	94,100	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	129,400	Consumption x cost
Pump	42,900	Consumption x cost
Direct Annual Costs (DAC)	**1,112,000**	

Indirect Annual Costs [C]		
Overhead	473,600	60% of O&M Labor
Administrative Charges	307,800	2% of Total Capital Investment
Property Taxes	153,900	1% of Total Capital Investment
Insurance	153,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	692,600	(Capital Investment) x (CFR of 0.08204)
Fabric Filter Annualized Costs[D]	569,800	(Capital Investment) x (CFR of 0.08204)
Indirect Annual Costs (IAC)	**2,351,600**	

Total Annualized Costs (TAC)	**3,463,600**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Interest Rate Comparison

473,600
307,800
153,900
153,900
607,309
499,632
2,196,141

3,308,100

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$

Interest (i)	5%	3.5%
Life (n)	20	20
CRF	0.08024	0.07036

CRK No. 1 Dry Sorbent Injection Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
DSI Equipment[B]	840,062	Vendor Quote
Control/Instrumentation[C]	84,000	10% of Equipment Cost
Sales Tax	50,400	6% of Equipment Cost
Freight[C]	42,000	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,016,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	864,000	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Flatwork/Drainage/Retrofit[D]	52,000	Estimated HDR
Total Direct Investment (TDI)	1,932,500	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	101,700	10% of TEC (Retrofit Adjustment, HDR)
Engineering	50,800	5% of TEC
Construction & Field Expense	101,700	10% of TEC
Contractor Fees	101,700	10% of TEC
Start-up Assistance	10,200	1% of TEC
Performance Test	20,300	2% of TEC (Adjusted HDR)
Total Indirect Investment (TII)	**386,400**	
Total Turnkey Cost (TTC)	**2,318,900**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 1 Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	31,000	Consumption x cost
Solids Fly Ash Disposal	15,200	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	13,000	Consumption x cost
Direct Annual Costs (DAC)	**136,700**	
Indirect Annual Costs [C]		
Overhead	65,100	60% of O&M Labor
Administrative Charges	46,400	2% of Total Capital Investment
Property Taxes	23,200	1% of Total Capital Investment
Insurance	23,200	1% of Total Capital Investment
DSI Annualized Costs[D]	190,200	(Capital Investment) x (CFR of 0.08204)
Indirect Annual Costs (IAC)	**348,100**	
Total Annualized Costs (TAC)	**484,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Interest Rate Comparison

65,100				
46,400				
23,200				
23,200	Interest (i)	5%	3.5%	
166,778	Life (n)	20	20	
324,678	CRF	0.08024	0.07036	
461,400				

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$

CRK No. 2 Dry FGD Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	3,369,794	Scaled Quote
Control/Instrumentation[C]	337,000	10% of Equipment Cost
Sales Tax	202,200	6% of Equipment Cost
Freight[C]	168,500	5% of Equipment Cost
Total Equipment Cost (TEC)	**4,077,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	3,465,900	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	154,800	Estimated by HDR
Exhaust Stack	97,300	Estimated by HDR
Retrofit Cost Addition	204,200	Estimated by HDR
Total Direct Investment (TDI)	7,999,700	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	122,300	3% of TEC
Engineering	407,800	10% of TEC
Construction & Field Expense	407,800	10% of TEC
Contractor Fees	407,800	10% of TEC
Start-up Assistance	40,800	1% of TEC
Performance Test	40,800	1% of TEC
Total Indirect Investment (TII)	**1,427,300**	
Total Turnkey Cost (TTC)	**9,427,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual,
Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 2 Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Fabric Filter Equipment[B]	2,930,256	Scaled Quote
Control/Instrumentation[C]	293,000	10% of Equipment Cost
Sales Tax	175,800	6% of Equipment Cost
Freight[C]	146,500	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,545,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	2,623,700	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	-	Included in SDA Costs
Exhaust Stack	-	Included in SDA Costs
Retrofit Cost Addition	-	Included in SDA Costs
Total Direct Investment (TDI)	6,169,300	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	106,400	3% of TEC
Engineering	354,600	10% of TEC
Construction & Field Expense	709,100	20% of TEC
Contractor Fees	354,600	10% of TEC
Start-up Assistance	35,500	1% of TEC
Performance Test	35,500	1% of TEC
Total Indirect Investment (TII)	**1,595,700**	

Total Turnkey Cost (TTC)	**7,765,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 2 Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	288,500	Consumption x cost
Fabric Filter Bag Replacement	192,100	Labor plus bag cost
Solids Scrubber Disposal	63,200	Production x cost
Solids Fly Ash Disposal	105,800	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	145,600	Consumption x cost
Pump	48,300	Consumption x cost
Direct Annual Costs (DAC)	**1,205,800**	

Indirect Annual Costs [C]		
Overhead	505,700	60% of O&M Labor
Administrative Charges	343,800	2% of Total Capital Investment
Property Taxes	171,900	1% of Total Capital Investment
Insurance	171,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	773,400	(Capital Investment) x (CFR of 0.08204)
Fabric Filter Annualized Costs[D]	637,000	(Capital Investment) x (CFR of 0.08204)
Indirect Annual Costs (IAC)	**2,603,700**	

Total Annualized Costs (TAC)	**3,809,500**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Interest Rate Comparison

505,700
343,800
171,900
171,900
678,159
558,556
2,430,016

3,635,800

$$CRF = i(1+i)^n / ((1+i)^n-1)$$

Interest (i)	5%	3.5%
Life (n)	20	20
CRF	0.08024	0.07036

CRK No. 2 Dry Sorbent Injection Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
DSI Equipment[B]	939,296	Vendor Quote
Control/Instrumentation[C]	93,900	10% of Equipment Cost
Sales Tax	56,400	6% of Equipment Cost
Freight[C]	47,000	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,136,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	966,100	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Flatwork/Drainage/Retrofit[D]	52,000	Estimated HDR
Total Direct Investment (TDI)	2,154,700	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	113,700	10% of TEC (Retrofit Adjustment, HDR)
Engineering	56,800	5% of TEC
Construction & Field Expense	113,700	10% of TEC
Contractor Fees	113,700	10% of TEC
Start-up Assistance	11,400	1% of TEC
Performance Test	22,700	2% of TEC (Adjusted HDR)
Total Indirect Investment (TII)	**432,000**	
Total Turnkey Cost (TTC)	**2,586,700**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 2 Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	34,700	Consumption x cost
Solids Fly Ash Disposal	17,000	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	14,500	Consumption x cost
Direct Annual Costs (DAC)	**143,700**	
Indirect Annual Costs [C]		
Overhead	67,300	60% of O&M Labor
Administrative Charges	51,700	2% of Total Capital Investment
Property Taxes	25,900	1% of Total Capital Investment
Insurance	25,900	1% of Total Capital Investment
DSI Annualized Costs[D]	212,200	(Capital Investment) x (CFR of 0.08204)
Indirect Annual Costs (IAC)	**383,000**	
Total Annualized Costs (TAC)	**526,700**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Interest Rate Comparison

67,300
51,700
25,900
25,900
186,069
356,869

500,600

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$

Interest (i)	5%	3.5%
Life (n)	20	20
CRF	0.08024	0.07036

CRK Dry Sorbent Injection Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
DSI Equipment[B]	1,832,000	Vendor Quote
Control/Instrumentation[C]	183,200	10% of Equipment Cost
Sales Tax	109,900	6% of Equipment Cost
Freight[C]	91,600	5% of Equipment Cost
Total Equipment Cost (TEC)	**2,216,700**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,884,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Total Direct Investment (TDI)	4,100,900	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	221,700	10% of TEC (Retrofit Adjustment, HDR)
Engineering	221,700	10% of TEC
Construction & Field Expense	221,700	10% of TEC
CFD Modeling	105,000	Vendor Quote
Contractor Fees	221,700	10% of TEC
Start-up Assistance	22,200	1% of TEC
Performance Test	44,300	2% of TEC (Adjusted HDR)
Total Indirect Investment (TII)	**1,058,300**	

Total Turnkey Cost (TTC)	**5,159,200**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, UCC, 2021.

DSI silo

Unloading Station

Mill and Compressor

No erection or installation

No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

CRK DSI Fabric Filter Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Fabric Filter Equipment[B]	11,087,100	Scaled Quote (Three Baghouses)
Control/Instrumentation[C]	1,108,700	10% of Equipment Cost
Sales Tax	665,200	6% of Equipment Cost
Freight[C]	554,400	5% of Equipment Cost
Total Equipment Cost (TEC)	**13,415,400**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	9,927,400	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Demolition of ESPs[D]	300,000	Demolition and Site Prep
Stack Replacement[D]	1,369,000	Extend three stacks to 200'
Total Direct Investment (TDI)	25,011,800	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	402,500	3% of TEC
Engineering	1,341,500	10% of TEC
Construction & Field Expense	2,683,100	20% of TEC
Contractor Fees	1,341,500	10% of TEC
Start-up Assistance	134,200	1% of TEC
Performance Test	134,200	1% of TEC
Total Indirect Investment (TII)	**6,037,000**	
Total Turnkey Cost (TTC)	**31,048,800**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled for capacity.

Capacity scaled using $C_n = r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Hammon Research-Cottrell, 2021

Pulse Jet Fabric Filter Baghouse

120 ft exhaust stack

No erection or installation

No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for fabric filters.

[D] Estimated by HDR.

CRK Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
DSI Labor	73,800	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	11,100	15% of labor
Fabric Filter Labor	291,600	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	43,700	15% of labor
Solvent (Trona)	1,227,600	Consumption x cost
Fabric Filter Bag Replacement	143,600	Labor plus bag cost
Solids Fly Ash Disposal	115,300	Production x cost
Maintenance Labor, Fabric F.	73,800	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	73,800	100% of labor
Maintenance Labor, DSI	73,800	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, DSI	73,800	100% of labor
DSI Electric Demand	47,100	785,185 kW/yr
Fabric F. Electrical Demand	62,700	348,400 kW/yr/unit
Direct Annual Costs (DAC)	**2,311,700**	

Description of Cost	($)[A]	Remarks
Indirect Annual Costs [C]		
Overhead	340,700	60% of O&M Labor
Administrative Charges	724,200	2% of Total Capital Investment
Property Taxes	362,100	1% of Total Capital Investment
Insurance	362,100	1% of Total Capital Investment
DSI Annualized Costs[D]	423,300	(Capital Investment) x (CFR of 0.08024)
Fabric Filter Annualized Costs[D]	2,547,200	(Capital Investment) x (CFR of 0.08024)
Indirect Annual Costs (IAC)	**4,759,600**	

Total Annualized Costs (TAC)	**7,071,300**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interest rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

From American Crystal Sugar SO2 Supplement (2022-02-02):

Table 2 – CRK SO_2 Cost of Compliance

Description	DSI
Emission Rate (lb/MMBtu)	0.12
Emission Reduction (tpy)	515
Capital Cost ($)	36,208,000
Direct Annual Cost ($)	2,311,700
Indirect Annual Cost ($)	4,759,600
Total Annualized Cost ($)	7,071,300
Cost Effectiveness ($/ton)	13,700

Interest Rate Comparison

340,700
724,200
362,100
362,100
363,000
2,184,600
4,336,700

6,648,400

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$

Interest (i)	5%	3.50%
Life (n)	20	20
CRF	0.08024	0.07036

Emission Reduction (tpy)	515
Cost Effectivness ($/ton)	12,900

Data Inputs (MPCA FFA Costs, Boise White Paper, Boiler 1, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 398.0 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 1,414,842,703 scf/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	351	days
Number of days the boiler operates (t_{plant})	351	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.131	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.08	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

Plant Elevation	1129	Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	2.87	$/MMBtu*		
Reagent ($Cost_{reag}$)	0.554	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	398	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	3,418,117,647	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,414,842,703	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.414	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3626	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	40	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	20.86	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	37.81	tons/year	94.525641
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	#VALUE!		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at 1129 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.1	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	20	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	70	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	9.3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	3,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	3.1	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	16	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.16	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$806,373	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,238,442	in 2019 dollars
Total Capital Investment (TCI) =	$2,658,260	in 2019 dollars

#VALUE!

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$806,373	in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

#VALUE!

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,238,442	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$61,518	in 2019 dollars
Indirect Annual Costs (IDAC) =	$188,338	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$249,856	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$39,874	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$18,736	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$960	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$241	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,708	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$61,518	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,196	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$187,141	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$188,338	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$249,856	per year in 2019 dollars
NOx Removed =	38	tons/year
Cost Effectiveness =	$6,608	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Boise White Paper, Boiler 1, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 398.0 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 1,414,842,703 scf/Year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1129 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	351	days		Number of SCR reactor chambers (n_{scr})	1	
Number of days the boiler operates (t_{plant})	351	days		Number of catalyst layers (R_{layer})	3	
Inlet NO_x Emissions (NOx_{in}) to SCR	0.131	lb/MMBtu		Number of empty catalyst layers (R_{empty})	1	
Outlet NO_x Emissions (NOx_{out}) from SCR	0.04	lb/MMBtu	80.0% Assumed Control efficiency	Ammonia Slip (Slip) provided by vendor	2	ppm
Stoichiometric Ratio Factor (SRF)	1.050			Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
				Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	144512	acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	330	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	398	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	3,418,117,647	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,414,842,703	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.414	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3626	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	69.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	36.22	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	65.66	tons/year	94.525641
NO_x removal factor (NRF) =	EF/80 =	0.87		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	144,512	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	24.34	/hour	
Residence Time	$1/V_{space}$	0.04	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)^*$ =	14.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.4914	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	5,937.37	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	151	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	14	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	173	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	13.2	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	94	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	14	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	49	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	204.65	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$8,031,851	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$336,571	in 2019 dollars
Indirect Annual Costs (IDAC) =	$568,451	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$905,022	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$40,159	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$13,015	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$62,629	in 2019 dollars
Annual Catalyst Replacement Cost =		$220,767	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$336,571	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,009	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$565,442	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$568,451	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$905,022	per year in 2019 dollars
NOx Removed =	66	tons/year
Cost Effectiveness =	$13,783	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boiler 3, SNCR, 2022-07-21)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 248 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,690 Btu/lb

What is the estimated actual annual fuel consumption? 66,810,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.33 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 5.33 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	256	days
Number of days the boiler operates (t_{plant})	256	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.39	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.23	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	250	Feet above sea level

Densities of typical SNCR reagents:

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	1.9	\$/MMBtu		
Reagent ($Cost_{reag}$)	0.554	\$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	\$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	\$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	\$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH_3) / (2000 lb/ton NH_3) * (0.29 lb NH_3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	248	MMBtu/hour	Natural Gas	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	249,997,699	lbs/Year	2,057,818,361	scf/Year
Actual Annual fuel consumption (Mactual) =		66,810,000	lbs/Year	99,060,000	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00			
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.315	fraction	0.048	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	2763	hours		
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	40	percent		
NOx removed per hour =	NOx_{in} x EF x Q_B =	38.59	lb/hour		
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	53.31	tons/year	133.27	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05			
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu		
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.	
Atmospheric pressure at 250 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia		
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00			

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	37	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	129	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	17.3	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	5,900	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	4.8	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	29	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.30	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1\times10^6)/HHV$ =	1.9	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$997,859 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,605,035 in 2019 dollars
Total Capital Investment (TCI) =	\$3,383,762 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$997,859 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$1,605,035 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$80,341	in 2019 dollars
Indirect Annual Costs (IDAC) =	$239,740	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$320,080	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$50,756	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$26,415	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,110	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$339	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,594	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$126	in 2019 dollars
Direct Annual Cost =		$80,341	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,523	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$238,217	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$239,740	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$320,080	per year in 2019 dollars
NOx Removed =	53	tons/year
Cost Effectiveness =	$6,004	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boiler 3, SCR, 2022-07-21)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 248 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,690 Btu/lb

What is the estimated actual annual fuel consumption? 66,810,000 lbs/Year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 250 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.33 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	256	days
Number of days the boiler operates (t_{plant})	256	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.39	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.06	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	248	MMBtu/hour	Natural Gas	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	249,997,699	lbs/Year	2,057,818,361	scf/Year
Actual Annual fuel consumption (Mactual) =		66,810,000	lbs/Year	99,060,000	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00			
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.315	fraction	0.048	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2763	hours		
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	85.0	percent		
NOx removed per hour =	NOx_{in} x EF x Q_B =	82.01	lb/hour		
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	113.28	tons/year	133.27	
NO_x removal factor (NRF) =	EF/80 =	1.06			
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	122,452	acfm		
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	115.52	/hour		
Residence Time	$1/V_{space}$	0.01	hour		
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05			
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu		
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.	
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia		
Retrofit Factor (RF)	Retrofit to existing boiler	1.00			

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.2373	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,060.03	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	128	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	147	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	12.1	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	32	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	110	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	15	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,000	gallons (storage needed to store a 14 day reagent supply rounded to the n

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0607

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	141.82	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$7,059,999	in 2019 dollars
Reagent Preparation Cost (RPC) =	$1,903,387	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$2,332,450	in 2019 dollars
Total Capital Investment (TCI) =	$14,684,586	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$7,059,999	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$1,903,387	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,332,450	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$147,979	in 2019 dollars
Indirect Annual Costs (IDAC) =	$894,079	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,042,058	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$73,423	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$22,453	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$33,070	in 2019 dollars
Annual Catalyst Replacement Cost =		$19,034	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$147,979	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,724	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$891,354	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$894,079	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,042,058	per year in 2019 dollars
NOx Removed =	113	tons/year
Cost Effectiveness =	$9,199	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boiler 3, Dry Scrubber, 2022-05-05)

Enter the following data for your combustion unit:

Is the FGD for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor. Enter 1 for projects of average difficulty. Enter values >1 for more difficult retrofits and enter <1 for less difficult retrofits. 1

Directions: Enter data in highlighted data fields.

What is the gross MW rating at full load capacity (A)? 21.4 MW

Provide the following information for the coal burned:

Select type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) percent by weight **OR** SO_2 Emissions (SO_{2in}) 0.27 lb/MMBtu

Oulet SO_2 Emissions (SO_{2out}) 0.05 lb/MMBtu

What is the higher heating value of the fuel (HHV)? Btu/lb

*HHV is the weighted average value calculated using the values entered in the coal blend composition table.

*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in lb/MMBtu above

What is the estimated actual annual MWh output? 67,065 MWh

Waste from a WFDG system disposed in an onsite or offsite landfill? Offsite Landfill

Gross heat input rate (GHR) 11.59 MMBtu/MWh

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t_{ABS})	6122 Hours	Plant Elevation	250 Feet above sea level
Number of hours the boiler operates (t_{plant})	6122 Hours		

Number of Full Time Operators (FT):

SDA System	1
WFGD system	1.5

Estimated equipment life:

SDA System	30 Years
Wet FGD System	30 Years
Estimated equipment life for mercury monitor for wastewater treatment system for Wet FGD Systems	6 Years

Enter the cost data for the proposed FGD System:

Desired dollar-year for Capital Costs	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI*
Annual Interest Rate (i)	3.5	Percent		

Sorbent Cost:

Lime (for SDA)	125.00	$/ton of Lime
Limestone (for Wet FGD)	30.00	$/ton of Limestone
Water ($Cost_{water}$)	0.0042	$/gallon
Electricity ($Cost_{elect}$)	0.0844	$/kWh
Waste Disposal cost ($Cost_{waste}$)	30.00	$/ton
Labor Rate	60.00	$/hour
Purchase Equipment Cost for Mercury Monitor for wastewater treatment System (MMCost)	100,000	$/monitor

*Note: CEPCI = Chemical Engineering Plant Cost Index. The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used
Lime ($/ton)	125	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Limestone ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Water Cost ($/gallon)	0.00420	Average water rates for industrial facilities (compiled by Black & Veatch. See '50 Largest Cities Water/Wastewater Rate Survey - 2018-2019.'Available at www.bv.com/sites/default/files/2019-10/50_Largest_Cities_Rate_Survey_2018_2019_Report.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Waste Disposal Cost ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Higher Heating Value (HHV) (Btu/lb)	8,826	Average HHV based 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Average Sulfur Content (%)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate March 2, 2021 (available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/).	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.
Hourly Labor Rate ($/hour)	60	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

Dry FGD Design Parameters

The following design parameters for the dry FGD system were calculated based on the values entered on the *FGD Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	A x GHR =	248	MMBtu/hour	
Maximum Annual MWh Output (B_{MW}) =	A x 8760 =	187,464	MWh	
Estimated Actual Annual MWh Output (B_{output}) =	Value entered by user	67,065	MWh	
Heat Rate Factor (HRF) =	Gross Plant Heat Rate/10 =	1.16		
Total System Capacity Factor (CF_{total}) =	$(B/B_{mw})*(t_{ABS}/t_{plant})$ =	0.358	fraction	
Total effective operating time for the scrubber (t_{op}) =	CF_{total} x 8760 =	3,134	hours	
SO_2 Removal Efficiency (EF) =	$(SO_{2in} - SO_{2out})/SO_{2in}$ =	80	percent	
SO_2 removed per hour =	SO_{2in} x EF x Q_B =	54	lb/hour	
Total SO_2 removed per year =	(SO_{2in} x EF x Q_B x t_{op})/2000 =	83.94	tons/year	104.92225
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
Inlet SO_2 Emissions (SO_{2in}) =	Value entered by user	0.27	lb/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 250 feet above sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0544

Waste Generation and Lime, Water and Power Consumption Rates:

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	[(0.000547 x S^2) + (0.00649 x S) + 1.3] x CoalF x HRF x (1/100) x A x 1,000 =	339	kW
Water Usage: Water consumption (q_{water}) =	[((0.04898 x S^2) + (0.5925 x S) + 55.11) x A x CoalF x HRF]/1,000	1.4	kgallons/hour
Lime Usage: Lime consumption rate (Q_{Lime}) =	[[((06702 x S^2)+(13.42 x S)) x A x HRF]/2,000] x (EF/0.95) =	0.04	tons/hour
Waste Generation: Waste generation rate (q_{waste}) =	[[((0.8016 x S^2) + (31.1917 x S)) x A x HRF]/2,000] x EF/0.95 =	0.1	lb/hour

SDA Cost Estimate

Total Capital Investment (TCI)

$$TCI = 1.3 \times (ABS_{cost} + BMF_{cost} + BOP_{cost})$$

Capital costs for the absorber (ABS_{cost}) =	$7,013,463
Reagent Preparation & Waste Recycling/handling (BMF_{cost}) =	$2,693,771
Balance of Plant Costs (BOP_{cost}) =	$9,777,195
Total Capital Investment (TCI) =	$25,329,758 in 2019 dollars

SDA Capital Costs ($_{cost}$)

For Coal-Fired Utility Boilers >600 MW:

$$ABS_{cost} = A \times 98{,}000 \times ELEVF$$

For Coal-Fired Utility Boilers 50 and 600 MW :

$$ABS_{cost} = 637{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.6} \times (S/4)^{0.01} \times ELEVF \times RF$$

SDA Capital Costs (ABS_{cost}) =	$7,013,463 in 2019 dollars

Reagent Preparation and Waste Recycling/Handling Costs (BMF_{cost})

For Coal-Fired Utility Boilers >600 MW:

$$BMF_{cost} = A \times 52{,}000$$

For Coal-Fired Utility Boilers 50 and 600 MW :

$$BMF_{cost} = 338{,}000 \times A^{0.716} \times (S \times HRF)^{0.2} \times RF$$

Reagent Preparation & Waste Recycling/Handling (BMF_{cost}) =	$2,693,771 in 2019 dollars

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers >600 MW:

$$BOP_{cost} = 138{,}000 \times A \times ELEVF$$

For Coal-Fired Utility Boilers betwee 50 and 600 MW :

$$BOP_{cost} = 899{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.4} \times ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$9,777,195 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$636,700	
Indirect Annual Costs (IDAC) =	$1,386,242	
Total annual costs (TAC) = DAC + IDAC	$2,022,942	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operator Cost) +(Annual Reagent Cost) + (Annual Make-up Water Cost) + (Annual Waste Disposal Cost) + (Annual Auxiliary Power Cost)

Annual Maintenance Cost =	0.015 x TCI =	$379,946	
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	$124,800	
Annual Reagent Cost =	Q_{lime} x $Cost_{reag}$ x t_{op} =	$15,022	
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$89,662	
Annual Make-up Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$18,945	
Annual Waste Disposal Cost =	q_{waste} x $Cost_{fuel}$ x t_{op} =	$8,325	
Direct Annual Cost =		$636,700	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Annual Operator Cost + 0.4(Annual Maintenance Cost)) =	$8,303	
Capital Recovery Costs (CR)=	CRF x TCI =	$1,377,939	
Indirect Annual Cost (IDAC) =	AC + CR =	$1,386,242	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ SO_2 Removed/year

Total Annual Cost (TAC) =	$2,022,942	per year in 2019 dollars
SO_2 Removed =	84	tons/year
Cost Effectiveness =	$24,100	per ton of SO_2 removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boiler 3, Wet Scrubber, 2022-05-05)

Enter the following data for your combustion unit:

Is the FGD for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor. Enter 1 for projects of average difficulty. Enter values >1 for more difficult retrofits and enter <1 for less difficult retrofits. 1

Directions: Enter data in highlighted data fields.

What is the gross MW rating at full load capacity (A)?	21.4	MW

Provide the following information for the coal burned:

Select type of coal burned:	Sub-Bituminous				
Enter the sulfur content (%S)		percent by weight	**OR**	SO_2 Emissions (SO_{2in})	0.27 lb/MMBtu
Oulet SO_2 Emissions (SO_{2out})	0.03	lb/MMBtu			
What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in the coal blend composition table.		Btu/lb	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in lb/MMBtu above		
What is the estimated actual annual MWh output?	67,065	MWh			
Waste from a WFDG system disposed in an onsite or offsite landfill?	Offsite Landfill				
Gross heat input rate (GHR)	11.59	MMBtu/MWh			

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t_{ABS})	6122 Hours	Plant Elevation	250 Feet above sea level
Number of hours the boiler operates (t_{plant})	6122 Hours		

Number of Full Time Operators (FT):

SDA System	1
WFGD system	1.5

Estimated equipment life:

SDA System	30	Years
Wet FGD System	30	Years
Estimated equipment life for mercury monitor for wastewater treatment system for Wet FGD Systems	6	Years

Enter the cost data for the proposed FGD System:

Desired dollar-year for Capital Costs	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI*
Annual Interest Rate (i)	3.5	Percent		

Sorbent Cost:

Lime (for SDA)	125.00	\$/ton of Lime
Limestone (for Wet FGD)	30.00	\$/ton of Limestone
Water ($Cost_{water}$)	0.0042	\$/gallon
Electricity ($Cost_{elect}$)	0.0844	\$/kWh
Waste Disposal cost ($Cost_{waste}$)	30.00	\$/ton
Labor Rate	60.00	\$/hour
Purchase Equipment Cost for Mercury Monitor for wastewater treatment System (MMCost)	100,000	\$/monitor

*Note: CEPCI = Chemical Engineering Plant Cost Index. The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used
Lime ($/ton)	125	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Limestone ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Water Cost ($/gallon)	0.00420	Average water rates for industrial facilities (compiled by Black & Veatch. See '50 Largest Cities Water/Wastewater Rate Survey - 2018-2019.'Available at www.bv.com/sites/default/files/2019-10/50_Largest_Cities_Rate_Survey_2018_2019_Report.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Waste Disposal Cost ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Higher Heating Value (HHV) (Btu/lb)	8,826	Average HHV based 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Average Sulfur Content (%)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate March 2, 2021 (available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/).	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.
Hourly Labor Rate ($/hour)	60	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

Wet FGD Design Parameters

The following design parameters for the wet FGD system were calculated based on the values entered on the *FGD Data Inputs* tab. These values were used to prepare the costs shown on the *Wet FGD*

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	A x GHR =	248	MMBtu/hour	
Maximum Annual MWh Output (B_{MW}) =	A x 8760 =	187,464	MWh	
Estimated Actual Annual MWh Output (B_{output}) =	Value entered by user	67,065	MWh	
Heat Rate Factor (HRF) =	Gross Plant Heat Rate/10 =	1.16		
Total System Capacity Factor (CF_{total}) =	$(B_{output}/B_{mw})*(t_{ABS}/t_{plant})$ =	0.358	fraction	
Total effective operating time for the scrubber (t_{op}) =	CF_{total} x 8760 =	3,134	hours	
SO_2 Removal Efficiency (EF) =	$(SO_{2in} - SO_{2out})/SO_{2in}$ =	90	percent	
SO_2 removed per hour =	SO_{2in} x EF x Q_B =	60	lb/hour	
Total SO_2 removed per year =	$(SO_{2in}$ x EF x Q_B x $t_{op})/2000$ =	94.43	tons/year	104.922252
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
Inlet SO_2 Emissions (SO_{2in}) =	Value entered by user	0.27	lb/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at
Atmospheric pressure at 250 feet above sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Capital Recovery Factor:

Parameter	Equation	Calculated Value	
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0544	Wet FGD System
		0.1877	Mercury Monitor for Wastewater Treatment System

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$0.0112e^{0.155xS}$ x CoalF x HRF x A x 1,000 =	304	kW
Water Usage: Water consumption (q_{water}) =	[(1.674 x S + 74.68) x A x CoalF x HRF]/1,000	2.0	kgallons/hour
Limestone Usage: Limestone consumption rate ($Q_{Limestone}$) =	[17.52 x A x S x HRF]/2,000] x (EF/0.98) =	0.05	tons/hour
Waste Generation: Waste generation rate (q_{waste}) =	[1.811 x $Q_{Limestone}$ x (EF/0.98) =	0.1	tons/hour
Wastewater Flow Rate: Wastewater flow rate (F) =	A x (0.4 gallons/min/MW) =	9	gallons/minute

Wet FGD Cost Estimate

Total Capital Investment (TCI)

$$TCI = 1.3 \times (ABS_{cost} + RPE_{cost} + WHE_{Cost} + BOP_{cost}) + WWT_{Cost}$$

Capital costs for the absorber (ABS_{cost}) =	$6,346,285	
Reagent Preparation Equipment Costs (RPE_{cost}) =	$1,433,295	
Waste Handling Equipment (WHE_{Cost}) =	$631,830	
Balance of Plant Costs (BOP_{cost}) =	$11,636,929	
Wastewater Treatment Facility Costs (WWT_{cost}) =	$11,640,022	
Total Capital Investment (TCI) =	$41,194,869	in 2019 dollars with disposal at offsite landfill

Wet FGD Capital Costs (ABS_{cost})

$$ABS_{cost} = 584{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.6} \times (S/2)^{0.02} \times ELEVF \times RF$$

Wet FGD Capital Costs (ABS_{cost}) =	$6,346,285	in 2019 dollars

Reagent Preparation Costs (RPE_{cost})

$$RPE_{cost} = 202{,}000 \times A^{0.716} \times (S \times HRF)^{0.3} \times RF$$

Reagent Preparation (RPE_{cost}) =	$1,433,295	in 2019 dollars

Waste Handling Equipment (WHE_{Cost})

$$WHE_{cost} = 106{,}000 \times A^{0.716} \times (S \times HRF)^{0.45} \times RF$$

Waste Recycling/Handling (WHE_{cost}) =	$631,830	in 2019 dollars

Balance of Plant Costs (BOP_{cost})

$$BOP_{cost} = 1{,}070{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.4} \times ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$11,636,929	in 2019 dollars

Wastewater Treatment Facility Costs (WWT_{cost})		
Wastewater Treatment Facility Costs with Onsite Landfill		
	WWT_{cost} = (41.36 F + 11,157,588) x RF x 0.898	
Wastewater Treatement Facility Costs with Offsite Landfill		
	WWT_{cost} = (41.16 F + 11,557,843) x RF x 0.898	
Wastewater Treatment Facility Costs (WWT_{cost}) =	$11,640,022	in 2019 dollars with disposal at offsite landfill

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,105,381	
Indirect Annual Costs (IDAC) =	$2,254,032	
Total annual costs (TAC) = DAC + IDAC	$3,359,413	in 2019 dollars

Direct Annual Costs (DAC)

DAC = Annual Maintenance Cost + Annual Operator Cost + Annual Reagent Cost + Annual Make-up Water Cost + Annual Waste Disposal Cost + Annual Auxiliary Power Cost + Annual Wastewater

Annual Maintenance Cost =	0.015 x TCI =	$617,923	
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	$187,200	
Annual Reagent Cost =	$Q_{limestone}$ x $Cost_{Limestone}$ x t_{op} =	$5,065	
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$80,438	
Annual Make-up Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$25,751	
Annual Waste Disposal Cost =	q_{waste} x $Cost_{fuel}$ x t_{op} =	$8,423	
Annual Wastewater Treatment Cost =	(6.3225F + 472,080) x 0.958 x CFtotal x ESC =	$161,811	(with disposal at offsite landfill)
Replacement Cost for Mercury Monitor =	CF_{mm} x MM_{Cost} =	$18,770	(replaced once every 6 years.)
Direct Annual Cost =		$1,105,381	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Annual Operator Cost + 0.4(Annual Maintenance Cost)) =	$13,031	
Capital Recovery Costs (CR)=	CRF x TCI =	$2,241,001	
Indirect Annual Cost (IDAC) =	AC + CR =	$2,254,032	in 2019 dollars

Cost Effectiveness = Total Annual Cost/ SO_2 Removed/year

Total Annual Cost (TAC) =	$3,359,413	per year in 2019 dollars
SO_2 Removed =	94	tons/year
Cost Effectiveness =	$35,576	per ton of SO_2 removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boilers 1&2, SNCR, 2022-07-21)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 216 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,690 Btu/lb

What is the estimated actual annual fuel consumption? 63,678,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.33 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 5.33 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	283	days
Number of days the boiler operates (t_{plant})	283	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.33	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.20	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

Plant Elevation	250	Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	1.9	$/MMBtu		
Reagent ($Cost_{reag}$)	0.554	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	216	MMBtu/hour	Natural Gas	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	217,739,931	lbs/Year	1,792,293,411	scf/Year
Actual Annual fuel consumption (Mactual) =		63,678,000	lbs/Year	126,000,000	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00			
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.363	fraction	0.070	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3178	hours		
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	40	percent		
NOx removed per hour =	NOx_{in} x EF x Q_B =	28.13	lb/hour		
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	44.70	tons/year	111.75	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05			
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu		
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.	
Atmospheric pressure at 250 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia		
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00			

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	27	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	94	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	12.6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	4,300	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	3.5	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	21	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.22	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	1.4	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$941,608 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,476,434 in 2019 dollars
Total Capital Investment (TCI) =	$3,143,455 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$941,608 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,476,434 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$71,959 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$222,714 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$294,673 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	\$47,152 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$22,150 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$931 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$284 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$1,337 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	\$105 in 2019 dollars
Direct Annual Cost =		\$71,959 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$1,415 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$221,299 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$222,714 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$294,673 per year in 2019 dollars
NOx Removed =	45 tons/year
Cost Effectiveness =	\$6,592 per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boilers 1&2, SCR, 2022-07-21)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 216 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,690 Btu/lb

What is the estimated actual annual fuel consumption? 63,678,000 lbs/Year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 250 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.33 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	283	days
Number of days the boiler operates (t_{plant})	283	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.33	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	216	MMBtu/hour	Natural Gas	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	217,739,931	lbs/Year	1,792,293,411	scf/Year
Actual Annual fuel consumption (Mactual) =		63,678,000	lbs/Year	126,000,000	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00			
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.363	fraction	0.070	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3178	hours		
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	85.0	percent		
NOx removed per hour =	NOx_{in} x EF x Q_B =	59.78	lb/hour		
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	94.99	tons/year	111.75	
NO_x removal factor (NRF) =	EF/80 =	1.06			
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	106,652	acfm		
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	117.97	/hour		
Residence Time	$1/V_{space}$	0.01	hour		
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05			
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu		
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.	
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia		
Retrofit Factor (RF)	Retrofit to existing boiler	1.00			

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.2373	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	904.04	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	111	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}))$ + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	128	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	11.3	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	23	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	80	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	11	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,600	gallons (storage needed to store a 14 day reagent supply rounded to the n

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0607

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	123.52	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	\$6,217,367	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$1,758,784	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$2,200,965	in 2019 dollars
Total Capital Investment (TCI) =	\$13,230,252	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	\$6,217,367 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	\$1,758,784 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$2,200,965 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$134,340 in 2019 dollars
Indirect Annual Costs (IDAC) =	$805,908 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$940,248 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$66,151 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$18,827 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$33,129 in 2019 dollars
Annual Catalyst Replacement Cost =		$16,233 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$134,340 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,831 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$803,076 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$805,908 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$940,248 per year in 2019 dollars
NOx Removed =	95 tons/year
Cost Effectiveness =	$9,899 per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boilers 1&2, Dry Scrubber, 2022-05-05)

Enter the following data for your combustion unit:

Is the FGD for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor. Enter 1 for projects of average difficulty. Enter values >1 for more difficult retrofits and enter <1 for less difficult retrofits. 1

Directions: Enter data in highlighted data fields.

What is the gross MW rating at full load capacity (A)?	17.8	MW

Provide the following information for the coal burned:

Select type of coal burned:	Sub-Bituminous					
Enter the sulfur content (%S)		percent by weight	OR	SO_2 Emissions (SO_{2in})	0.30	lb/MMBtu
Oulet SO_2 Emissions (SO_{2out})	0.06	lb/MMBtu				
What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in the coal blend composition table.		Btu/lb	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in lb/MMBtu above			
What is the estimated actual annual MWh output?	59,745	MWh				
Waste from a WFDG system disposed in an onsite or offsite landfill?	Offsite Landfill					
Gross heat input rate (GHR)	12.13	MMBtu/MWh				

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t_{ABS})	6783 Hours	Plant Elevation	250 Feet above sea level
Number of hours the boiler operates (t_{plant})	6783 Hours		

Number of Full Time Operators (FT):

SDA System	1
WFGD system	1.5

Estimated equipment life:

SDA System	30 Years
Wet FGD System	30 Years
Estimated equipment life for mercury monitor for wastewater treatment system for Wet FGD Systems	6 Years

Enter the cost data for the proposed FGD System:

Desired dollar-year for Capital Costs	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI*
Annual Interest Rate (i)	3.5	Percent		

Sorbent Cost:

Lime (for SDA)	125.00	$/ton of Lime
Limestone (for Wet FGD)	30.00	$/ton of Limestone
Water ($Cost_{water}$)	0.0042	$/gallon
Electricity ($Cost_{elect}$)	0.0844	$/kWh
Waste Disposal cost ($Cost_{waste}$)	30.00	$/ton
Labor Rate	60.00	$/hour
Purchase Equipment Cost for Mercury Monitor for wastewater treatment System (MMCost)	100,000	$/monitor

*Note: CEPCI = Chemical Engineering Plant Cost Index. The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used
Lime ($/ton)	125	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Limestone ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Water Cost ($/gallon)	0.00420	Average water rates for industrial facilities (compiled by Black & Veatch. See '50 Largest Cities Water/Wastewater Rate Survey - 2018-2019.'Available at www.bv.com/sites/default/files/2019-10/50_Largest_Cities_Rate_Survey_2018_2019_Report.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Waste Disposal Cost ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Higher Heating Value (HHV) (Btu/lb)	8,826	Average HHV based 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Average Sulfur Content (%)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate March 2, 2021 (available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/).	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.
Hourly Labor Rate ($/hour)	60	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

Dry FGD Design Parameters

The following design parameters for the dry FGD system were calculated based on the values entered on the *FGD Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	A x GHR =	216	MMBtu/hour	
Maximum Annual MWh Output (B_{MW}) =	A x 8760 =	155,928	MWh	
Estimated Actual Annual MWh Output (B_{output}) =	Value entered by user	59,745	MWh	
Heat Rate Factor (HRF) =	Gross Plant Heat Rate/10 =	1.21		
Total System Capacity Factor (CF_{total}) =	$(B/B_{mw})*(t_{ABS}/t_{plant})$ =	0.383	fraction	
Total effective operating time for the scrubber (t_{op}) =	CF_{total} x 8760 =	3,356	hours	
SO_2 Removal Efficiency (EF) =	$(SO_{2in} - SO_{2out})/SO_{2in}$ =	80	percent	
SO_2 removed per hour =	SO_{2in} x EF x Q_B =	52	lb/hour	
Total SO_2 removed per year =	$(SO_{2in}$ x EF x Q_B x $t_{op})/2000$ =	87.00	tons/year	108.74933
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
Inlet SO_2 Emissions (SO_{2in}) =	Value entered by user	0.30	lb/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 250 feet above sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0544

Waste Generation and Lime, Water and Power Consumption Rates:

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	[(0.000547 x S^2) + (0.00649 x S) + 1.3] x CoalF x HRF x (1/100) x A x 1,000 =	295	kW
Water Usage: Water consumption (q_{water}) =	[((0.04898 x S^2) + (0.5925 x S) + 55.11) x A x CoalF x HRF]/1,000	1.3	kgallons/hour
Lime Usage: Lime consumption rate (Q_{Lime}) =	[[((06702 x S^2)+(13.42 x S)) x A x HRF]/2,000] x (EF/0.95) =	0.04	tons/hour
Waste Generation: Waste generation rate (q_{waste}) =	[[((0.8016 x S^2) + (31.1917 x S)) x A x HRF]/2,000] x EF/0.95 =	0.1	lb/hour

SDA Cost Estimate

Total Capital Investment (TCI)

$$TCI = 1.3 \times (ABS_{cost} + BMF_{cost} + BOP_{cost})$$

Capital costs for the absorber (ABS_{cost}) =	$6,325,750
Reagent Preparation & Waste Recycling/handling (BMF_{cost}) =	$2,433,525
Balance of Plant Costs (BOP_{cost}) =	$8,728,449
Total Capital Investment (TCI) =	$22,734,042 in 2019 dollars

SDA Capital Costs ($_{cost}$)

For Coal-Fired Utility Boilers >600 MW:

$$ABS_{cost} = A \times 98{,}000 \times ELEVF$$

For Coal-Fired Utility Boilers 50 and 600 MW :

$$ABS_{cost} = 637{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.6} \times (S/4)^{0.01} \times ELEVF \times RF$$

SDA Capital Costs (ABS_{cost}) =	$6,325,750 in 2019 dollars

Reagent Preparation and Waste Recycling/Handling Costs (BMF_{cost})

For Coal-Fired Utility Boilers >600 MW:

$$BMF_{cost} = A \times 52{,}000$$

For Coal-Fired Utility Boilers 50 and 600 MW :

$$BMF_{cost} = 338{,}000 \times A^{0.716} \times (S \times HRF)^{0.2} \times RF$$

Reagent Preparation & Waste Recycling/Handling (BMF_{cost}) =	$2,433,525 in 2019 dollars

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers >600 MW:

$$BOP_{cost} = 138{,}000 \times A \times ELEVF$$

For Coal-Fired Utility Boilers betwee 50 and 600 MW :

$$BOP_{cost} = 899{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.4} \times ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$8,728,449 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$591,369	
Indirect Annual Costs (IDAC) =	$1,244,568	
Total annual costs (TAC) = DAC + IDAC	$1,835,937	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operator Cost) +(Annual Reagent Cost) + (Annual Make-up Water Cost) + (Annual Waste Disposal Cost) + (Annual Auxiliary Power Cost)

Annual Maintenance Cost =	0.015 x TCI =	$341,011	
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	$124,800	
Annual Reagent Cost =	Q_{lime} x $Cost_{reag}$ x t_{op} =	$15,592	
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$83,652	
Annual Make-up Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$17,678	
Annual Waste Disposal Cost =	q_{waste} x $Cost_{fuel}$ x t_{op} =	$8,636	
Direct Annual Cost =		$591,369	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Annual Operator Cost + 0.4(Annual Maintenance Cost)) =	$7,836	
Capital Recovery Costs (CR)=	CRF x TCI =	$1,236,732	
Indirect Annual Cost (IDAC) =	AC + CR =	$1,244,568	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ SO_2 Removed/year

Total Annual Cost (TAC) =	$1,835,937	per year in 2019 dollars
SO_2 Removed =	87	tons/year
Cost Effectiveness =	$21,103	per ton of SO_2 removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boilers 1&2, Wet Scrubber, 2022-05-05)

Enter the following data for your combustion unit:

Is the FGD for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor. Enter 1 for projects of average difficulty. Enter values >1 for more difficult retrofits and enter <1 for less difficult retrofits. 1

Directions: Enter data in highlighted data fields.

What is the gross MW rating at full load capacity (A)? 17.8 MW

Provide the following information for the coal burned:

Select type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) percent by weight **OR** SO_2 Emissions (SO_{2in}) 0.30 lb/MMBtu

Oulet SO_2 Emissions (SO_{2out}) 0.03 lb/MMBtu

What is the higher heating value of the fuel (HHV)? Btu/lb

*HHV is the weighted average value calculated using the values entered in the coal blend composition table.

*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in lb/MMBtu above

What is the estimated actual annual MWh output? 59,745 MWh

Waste from a WFDG system disposed in an onsite or offsite landfill? Offsite Landfill

Gross heat input rate (GHR) 12.13 MMBtu/MWh

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t_{ABS})	6783	Hours	Plant Elevation	250 Feet above sea level
Number of hours the boiler operates (t_{plant})	6783	Hours		

Number of Full Time Operators (FT):

SDA System	1	
WFGD system	1.5	

Estimated equipment life:

SDA System	30	Years
Wet FGD System	30	Years
Estimated equipment life for mercury monitor for wastewater treatment system for Wet FGD Systems	6	Years

Enter the cost data for the proposed FGD System:

Desired dollar-year for Capital Costs	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI*
Annual Interest Rate (i)	3.5	Percent		

Sorbent Cost:

Lime (for SDA)	125.00	\$/ton of Lime
Limestone (for Wet FGD)	30.00	\$/ton of Limestone
Water ($Cost_{water}$)	0.0042	\$/gallon
Electricity ($Cost_{elect}$)	0.0844	\$/kWh
Waste Disposal cost ($Cost_{waste}$)	30.00	\$/ton
Labor Rate	60.00	\$/hour
Purchase Equipment Cost for Mercury Monitor for wastewater treatment System (MMCost)	100,000	\$/monitor

*Note: CEPCI = Chemical Engineering Plant Cost Index. The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used
Lime ($/ton)	125	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Limestone ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Water Cost ($/gallon)	0.00420	Average water rates for industrial facilities (compiled by Black & Veatch. See '50 Largest Cities Water/Wastewater Rate Survey - 2018-2019.'Available at www.bv.com/sites/default/files/2019-10/50_Largest_Cities_Rate_Survey_2018_2019_Report.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Waste Disposal Cost ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Higher Heating Value (HHV) (Btu/lb)	8,826	Average HHV based 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Average Sulfur Content (%)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate March 2, 2021 (available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/).	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.
Hourly Labor Rate ($/hour)	60	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

Wet FGD Design Parameters

The following design parameters for the wet FGD system were calculated based on the values entered on the *FGD Data Inputs* tab. These values were used to prepare the costs shown on the *Wet FGD*

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	A x GHR =	216	MMBtu/hour	
Maximum Annual MWh Output (B_{MW}) =	A x 8760 =	155,928	MWh	
Estimated Actual Annual MWh Output (B_{output}) =	Value entered by user	59,745	MWh	
Heat Rate Factor (HRF) =	Gross Plant Heat Rate/10 =	1.21		
Total System Capacity Factor (CF_{total}) =	$(B_{output}/B_{mw})*(t_{ABS}/t_{plant})$ =	0.383	fraction	
Total effective operating time for the scrubber (t_{op}) =	CF_{total} x 8760 =	3,356	hours	
SO_2 Removal Efficiency (EF) =	$(SO_{2in} - SO_{2out})/SO_{2in}$ =	90	percent	
SO_2 removed per hour =	SO_{2in} x EF x Q_B =	58	lb/hour	
Total SO_2 removed per year =	$(SO_{2in}$ x EF x Q_B x $t_{op})/2000$ =	97.87	tons/year	108.749326
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
Inlet SO_2 Emissions (SO_{2in}) =	Value entered by user	0.30	lb/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at
Atmospheric pressure at 250 feet above sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Capital Recovery Factor:

Parameter	Equation	Calculated Value	
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0544	Wet FGD System
		0.1877	Mercury Monitor for Wastewater Treatment System

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$0.0112e^{0.155xS}$ x CoalF x HRF x A x 1,000 =	266	kW
Water Usage: Water consumption (q_{water}) =	[(1.674 x S + 74.68) x A x CoalF x HRF]/1,000	1.7	kgallons/hour
Limestone Usage: Limestone consumption rate ($Q_{Limestone}$) =	[17.52 x A x S x HRF]/2,000] x (EF/0.98) =	0.05	tons/hour
Waste Generation: Waste generation rate (q_{waste}) =	[1.811 x $Q_{Limestone}$ x (EF/0.98) =	0.1	tons/hour
Wastewater Flow Rate: Wastewater flow rate (F) =	A x (0.4 gallons/min/MW) =	7	gallons/minute

Wet FGD Cost Estimate

Total Capital Investment (TCI)

$$TCI = 1.3 \times (ABS_{cost} + RPE_{cost} + WHE_{Cost} + BOP_{cost}) + WWT_{Cost}$$

Capital costs for the absorber (ABS_{cost}) =	$5,730,027	
Reagent Preparation Equipment Costs (RPE_{cost}) =	$1,314,577	
Waste Handling Equipment (WHE_{Cost}) =	$592,808	
Balance of Plant Costs (BOP_{cost}) =	$10,388,699	
Wastewater Treatment Facility Costs (WWT_{cost}) =	$11,639,963	
Total Capital Investment (TCI) =	$38,565,895	in 2019 dollars with disposal at offsite landfill

Wet FGD Capital Costs (ABS_{cost})

$$ABS_{cost} = 584{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.6} \times (S/2)^{0.02} \times ELEVF \times RF$$

Wet FGD Capital Costs (ABS_{cost}) =	$5,730,027	in 2019 dollars

Reagent Preparation Costs (RPE_{cost})

$$RPE_{cost} = 202{,}000 \times A^{0.716} \times (S \times HRF)^{0.3} \times RF$$

Reagent Preparation (RPE_{cost}) =	$1,314,577	in 2019 dollars

Waste Handling Equipment (WHE_{Cost})

$$WHE_{cost} = 106{,}000 \times A^{0.716} \times (S \times HRF)^{0.45} \times RF$$

Waste Recycling/Handling (WHE_{cost}) =	$592,808	in 2019 dollars

Balance of Plant Costs (BOP_{cost})

$$BOP_{cost} = 1{,}070{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.4} \times ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$10,388,699	in 2019 dollars

Wastewater Treatment Facility Costs (WWT_{cost})	
Wastewater Treatment Facility Costs with Onsite Landfill	
	WWT_{cost} = (41.36 F + 11,157,588) x RF x 0.898
Wastewater Treatement Facility Costs with Offsite Landfill	
	WWT_{cost} = (41.16 F + 11,557,843) x RF x 0.898
Wastewater Treatment Facility Costs (WWT_{cost}) =	$11,639,963 in 2019 dollars with disposal at offsite landfill

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,071,160	
Indirect Annual Costs (IDAC) =	$2,110,543	
Total annual costs (TAC) = DAC + IDAC	$3,181,703	in 2019 dollars

Direct Annual Costs (DAC)

DAC = Annual Maintenance Cost + Annual Operator Cost + Annual Reagent Cost + Annual Make-up Water Cost + Annual Waste Disposal Cost + Annual Auxiliary Power Cost + Annual Wastewater

Annual Maintenance Cost =	0.015 x TCI =	$578,488	
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	$187,200	
Annual Reagent Cost =	$Q_{limestone}$ x $Cost_{Limestone}$ x t_{op} =	$5,249	
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$75,384	
Annual Make-up Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$24,037	
Annual Waste Disposal Cost =	q_{waste} x $Cost_{fuel}$ x t_{op} =	$8,730	
Annual Wastewater Treatment Cost =	(6.3225F + 472,080) x 0.958 x CFtotal x ESC =	$173,301	(with disposal at offsite landfill)
Replacement Cost for Mercury Monitor =	CF_{mm} x MM_{Cost} =	$18,770	(replaced once every 6 years.)
Direct Annual Cost =		$1,071,160	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Annual Operator Cost + 0.4(Annual Maintenance Cost)) =	$12,558	
Capital Recovery Costs (CR)=	CRF x TCI =	$2,097,985	
Indirect Annual Cost (IDAC) =	AC + CR =	$2,110,543	in 2019 dollars

Cost Effectiveness = Total Annual Cost/ SO_2 Removed/year

Total Annual Cost (TAC) =	$3,181,703	per year in 2019 dollars
SO_2 Removed =	98	tons/year
Cost Effectiveness =	$32,508	per ton of SO_2 removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boiler 7, SCR, 2022-07-21)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Coal

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 230 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 4,450 Btu/lb

What is the estimated actual annual fuel consumption? 105,728,000 lbs/Year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1440 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 0.02 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (•) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	119 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	119 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.13 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.03 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	516 ft^3/min-MMBtu/hour

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5 Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.5 Percent	
Reagent ($Cost_{reag}$)	0.554 $/gallon for 29% ammonia	
Electricity ($Cost_{elect}$)	0.0844 $/kWh	
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	230	MMBtu/hour	Natural Gas	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	452,814,923	lbs/Year	1,908,460,577	scf/Year
Actual Annual fuel consumption (Mactual) =		105,728,000	lbs/Year	27,160,000	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00			
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.248	fraction	0.014	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2170	hours		
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	78.0	percent		
NOx removed per hour =	NOx_{in} x EF x Q_B =	22.97	lb/hour		
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	24.92	tons/year	31.946	
NO_x removal factor (NRF) =	EF/80 =	0.98			
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	113,564	acfm		
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	136.72	/hour		
Residence Time	$1/V_{space}$	0.01	hour		
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07			
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05			
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.0	psia		
Retrofit Factor (RF)	Retrofit to existing boiler	1.00			

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.1105	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	830.64	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	118	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	136	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	11.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	9	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	31	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,400	gallons (storage needed to store a 14 day reagent supply rounded to the n

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0607

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	132.60	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	\$6,937,059	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$1,384,659	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$2,398,314	in 2019 dollars
Total Capital Investment (TCI) =	\$13,936,042	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	\$6,937,059	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	\$1,384,659	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$2,398,314	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$105,851	in 2019 dollars
Indirect Annual Costs (IDAC) =	$847,611	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$953,462	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$69,680	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$4,939	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$24,286	in 2019 dollars
Annual Catalyst Replacement Cost =		$6,945	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$105,851	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$1,693	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$845,918	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$847,611	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$953,462	per year in 2019 dollars
NOx Removed =	24.9	tons/year
Cost Effectiveness =	$38,261	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Northshore Mining Company, Boiler 1, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.3

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	517	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	8,625	Btu/lb
What is the estimated actual annual fuel consumption?	395,118,000	lbs/Year
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.22 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 5.08 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	339	days
Number of days the boiler operates (t_{plant})	339	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.391209466	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.293	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	0.95	

Plant Elevation	764 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	1.9	$/MMBtu		
Reagent ($Cost_{reag}$)	1.660	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	517	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	525,092,135	lbs/Year	
Actual Annual fuel consumption (Mactual) =		395,118,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.752	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	6592	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	50.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	166.65	tons/year	666.6
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at 764 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.30		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	125	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	250	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	26.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	8,900	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	9.0	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	120	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.01	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	6.0	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,814,402	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,746,588	in 2019 dollars
Total Capital Investment (TCI) =	$5,929,287	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,814,402	in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,746,588	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$399,234 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$420,090 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$819,324 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	\$88,939 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$288,344 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$5,010 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$3,295 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$12,686 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	\$960 in 2019 dollars
Direct Annual Cost =		\$399,234 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$2,668 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$417,422 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$420,090 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$819,324 per year in 2019 dollars
NOx Removed =	167 tons/year
Cost Effectiveness =	\$4,916 per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Northshore Mining Company, Boiler 1, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	175	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	8,625	Btu/lb
What is the estimated actual annual fuel consumption?	42,518,000	lbs/year
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1440 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.32 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Parameter	Value	Units
Number of days the SCR operates (t_{SCR})	211	days
Number of days the boiler operates (t_{plant})	211	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.39	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.06	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Parameter	Value	Units
Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Parameter	Value	Units
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Parameter	Value	Units
Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Parameter	Value	Units
Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Parameter	Value	Units / Notes
Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI
Annual Interest Rate (i)	3.5	Percent
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0844	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	175	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	177,739,130	lbs/year	
Actual Annual fuel consumption (Mactual) =		42,518,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.239	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2096	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	85.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	57.42	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	60.16	tons/year	70.776526
NO_x removal factor (NRF) =	EF/80 =	1.06		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	86,408	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	115.69	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05		
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1865	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	746.88	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	90	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	104	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	10.2	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	22	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	77	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	10	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,500	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0607

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	100.08	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$5,393,867	in 2019 dollars
Reagent Preparation Cost (RPC) =	$1,741,116	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$2,121,362	in 2019 dollars
Total Capital Investment (TCI) =	$12,033,247	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$5,393,867	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$1,741,116	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,121,362	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$100,330 in 2019 dollars
Indirect Annual Costs (IDAC) =	$732,659 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$832,990 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$60,166 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$11,924 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$17,700 in 2019 dollars
Annual Catalyst Replacement Cost =		$10,540 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR)$ x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x $(CC_{replace})$ x 35.3	
Direct Annual Cost =		$100,330 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,241 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$730,418 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$732,659 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$832,990 per year in 2019 dollars
NOx Removed =	60 tons/year
Cost Effectiveness =	$13,846 per ton of NOx removed in 2019 dollars

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-3: NO_x Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Operating Unit: **Power Boiler 2**

Emission Unit Number	EQUI 15 / EU 002		Stack/Vent Number	SV 002	
Desgin Capacity	765	MMBtu/hr	Standardized Flow Rate	157,508	scfm @ 32º F
Expected Utiliztion Rate	78%		Temperature	265	Deg F
Expected Annual Hours of Operation	5,774	Hours	Moisture Content	11.0%	
Annual Interest Rate	3.5%		Actual Flow Rate	232,100	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	163,800	scfm @ 68º F
			Dry Std Flow Rate	145,700	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**2,948,468**
Purchased Equipment Total (B)	14%	of control device cost (A)	**3,357,568**
Installation - Standard Costs	95%	of purchased equip cost (B)	3,189,689
Installation - Site Specific Costs			1,218,983
Installation Total			3,189,689
Total Direct Capital Cost, DC			6,547,257
Total Indirect Capital Costs, IC	68%	of purchased equip cost (B)	5,062,104
Total Capital Investment (TCI) = DC + IC			**11,609,362**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	277,985
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	1,277,034
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,555,019**

Notes & Assumptions

1 Cost estimate from vendor engineering estimate scaled for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
2 Installation cost assumptions and calculation methodology based on vendor engineering estimates
3 Maintenance and replacement power costs based on vendor engineering estimate
4 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-3: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**2,948,468**
Purchased Equipment Costs (A)			
Instrumentation	2%	of control device cost (A)	58,969
MN Sales Taxes	6.9%	of control device cost (A)	202,707
Freight	5%	of control device cost (A)	147,423
Purchased Equipment Total (B)	14%		**3,357,568**
Installation [1]			
Foundations & supports	30%	of purchased equip cost (B)	1,007,270
Handling & erection	20%	of purchased equip cost (B)	671,514
Electrical	20%	of purchased equip cost (B)	671,514
Piping	10%	of purchased equip cost (B)	335,757
Insulation	10%	of purchased equip cost (B)	335,757
Painting	2.5%	of purchased equip cost (B)	83,939
Demolition	2.5%	of purchased equip cost (B)	83,939
Installation Subtotal Standard Expenses	95%		**3,189,689**
Installation Total			**3,189,689**
Total Direct Capital Cost, DC			**6,547,257**
Indirect Capital Costs			
Engineering, supervision	15%	of direct costs (DC)	982,089
Owner's cost	10%	of direct costs (DC)	654,726
Construction & field expenses	5%	of direct costs (DC)	327,363
Contractor fees	15%	of direct costs (DC)	982,089
Start-up and spare parts	2%	of direct costs (DC)	130,945
Performance test	1%	Engineering estimate	50,000
Model Studies	NA	of direct costs (DC)	N/A
Contingencies	20%	of direct costs (DC) and indirect costs (IC) above	1,934,894
Total Indirect Capital Costs, IC	68%	of direct costs (DC)	**5,062,104**
Total Capital Investment (TCI) = DC + IC			**11,609,362**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Allowance for funds used during construciton	10.5%	of DC + IC	1,218,983
Total Site Specific Costs			**1,218,983**
TCI with site specifics for capital recovery cost			**12,828,344**
Total Capital Investment (TCI) with Retrofit Factor	0%	No retrofit factor needed based on site-specific analysis	**12,828,344**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance labor and materials	3%	of direct capital (DC) costs	196,418
Utilities, Supplies, Replacements & Waste Management			
Replacement power from efficiency loss	NA	0.2% OFA efficiency drop per engineering estimates	81,567
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**277,985**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	117,851
Administration (2% total capital costs)	2%	of total capital costs (TCI)	256,567
Property tax (1% total capital costs)	N/A	of total capital costs (TCI)	0
Insurance (1% total capital costs)	N/A	Already included in costs above	0
Capital Recovery	7%	for a 20- year equipment life and a 3.5% interest rate	902,616
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,277,034**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,555,019**

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-3: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Capital Recovery Factors		
Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations from Engineering Vendor

Operating Hours 5,774
Utilization Rate: 78%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Operating Unit: **Power Boiler 1**

Emission Unit Number			Stack/Vent Number		
Design Capacity	517	MMBtu/hr	Standardized Flow Rate	133,505	scfm @ 32º F
Utilization Rate	73%		Exhaust Temperature	280	Deg F
Annual Operating Hours	5,650	hr/yr	Exhaust Moisture Content	8.8%	
Annual Interest Rate	3.50%		Actual Flow Rate	200,800	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	140,800	scfm @ 68º F
Plant Elevation	764	ft	Dry Std Flow Rate	128,300	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**8,140,624**
Purchased Equipment Total (B)	22%	of control device cost (A)				**9,921,386**
Installation - Standard Costs	74%	of purchased equip cost (B)				7,341,825
Installation - Site Specific Costs						N/A
Installation Total						7,341,825
Total Direct Capital Cost, DC						17,263,211
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				5,159,121
Total Capital Investment (TCI) = DC + IC						**21,539,732**
Adjusted TCI for Replacement Parts						21,539,732
Total Capital Investment (TCI) with Retrofit Factor						**28,001,651**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.				1,551,147
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				3,395,099
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**4,946,246**

Notes & Assumptions

1 Baghouse cost estimate from 2008 vendor data for 165,000 acfm baghouse, (Northshore Mining March 2009 submittal to MPCA)
2 Purchased equipment costs include anciliary equipment
3 Costs scaled up to design airflow using the 6/10 power law
4 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
5 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
6 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**8,140,624**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	814,062
State Sales Taxes	6.9%	of control device cost (A)	559,668
Freight	5%	of control device cost (A)	407,031
Purchased Equipment Total (B)	22%		**9,921,386**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	396,855
Handling & erection	50%	of purchased equip cost (B)	4,960,693
Electrical	8%	of purchased equip cost (B)	793,711
Piping	1%	of purchased equip cost (B)	99,214
Insulation	7%	of purchased equip cost (B)	694,497
Painting	4%	Included in vendor estimate	396,855
Installation Subtotal Standard Expenses	74%		**7,341,825**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**7,341,825**
Total Direct Capital Cost, DC			**17,263,211**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	992,139
Construction & field expenses	20%	of purchased equip cost (B)	1,984,277
Contractor fees	10%	of purchased equip cost (B)	992,139
Start-up	1%	of purchased equip cost (B)	99,214
Performance test	1%	of purchased equip cost (B)	99,214
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	992,139
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,159,121**
Total Capital Investment (TCI) = DC + IC			**22,422,332**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**21,539,732**
Total Capital Investment (TCI) with Retrofit Factor	30%		**28,001,651**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr	84,750
Supervisor	0.15	of Op Labor	12,713
Maintenance			
Maintenance Labor	60.00	$/Hr	42,375
Maintenance Materials	100	% of Maintenance Labor	42,375
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 218.1 kW-hr, 5650 hr/yr, 73% utilization	93,639
N/A			-
Compressed Air	0.47	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization	46,447
N/A			-
Solid Waste Disposal	41.32	$/ton, 0.5 ton/hr, 5650 hr/yr, 73% utilization	81,723
Trona	285.00	$/ton, 1,193.8 lb/hr, 5650 hr/yr, 73% utilization	701,646
Filter Bags	249.27	$/bag, 2,952 bags, 5650 hr/yr, 73% utilization	195,479
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,551,147**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	109,328
Administration (2% total capital costs)	2%	of total capital costs (TCI)	560,033
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	280,017
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	280,017
Capital Recovery	0.0704	for a 20-year equipment life and a 3.5% interest rate	1,970,226
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**3,395,099**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,946,246**

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Capital Recovery Factors

Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	5	years
CRF	0.2215	
Rep part cost per unit	249.27	$/bag
Amount Required	2952	# of Bags for new baghouse
Total Rep Parts Cost	823,565	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	59,035	20 min per bag
Total Installed Cost	**882,600**	
Annualized Cost	**195,479**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	200,800	6.00	1,232,089	Electricity for new baghouse
Total			1,232,089	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	214.87	lb/hr SO2	1193.80	lb/hr Trona
Solid Waste Disposal	2,709	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	73%	Annual Operating Hours	5,650					
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,413	$	84,750	$/Hr, 2.0 hr/8 hr shift, 1,413 hr/yr
Supervisor	15%	of Op Labor			NA	$	12,713	% of Operator Costs
Maintenance								
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	706	$	42,375	$/Hr, 1.0 hr/8 hr shift, 706 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	42,375	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.076	$/kwh	218.1	kW-hr	1,232,089	$	93,639	$/kwh, 218.1 kW-hr, 5650 hr/yr, 73% utilization
Water			N/A	gpm				
Compressed Air	0.467	$/kscf	2.0	scfm/kacfm	99,384	$	46,447	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization
Cooling Water			N/A	gpm				
Solid Waste Disposal	41.32	$/ton	0.5	ton/hr	1,978	$	81,723	$/ton, 0.5 ton/hr, 5650 hr/yr, 73% utilization
Trona	285.00	$/ton	1,193.8	lb/hr	2,462	$	701,646	$/ton, 1,193.8 lb/hr, 5650 hr/yr, 73% utilization
Filter Bags	249.27	$/bag	2,952	bags	N/A	$	195,479	$/bag, 2,952 bags, 5650 hr/yr, 73% utilization

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Operating Unit: **Power Boiler 1**

Emission Unit Number	EQUI 14 / EU 001		Stack/Vent Number	SV 001	
Design Capacity	517	MMBtu/hr	Standardized Flow Rate	133,505	scfm @ 32º F
Utilization Rate	73%		Temperature	280	Deg F
Annual Operating Hours	5,650	Hours	Moisture Content	8.8%	
Annual Interest Rate	3.5%		Actual Flow Rate	200,800	acfm
Equipment Life	20	yrs	Standardized Flow Rate	140,800	scfm @ 68º F
			Dry Std Flow Rate	128,300	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**21,325,238**
Purchased Equipment Total (B)	22%	of control device cost (A)	**25,990,134**
Installation - Standard Costs	74%	of purchased equip cost (B)	19,232,699
Installation - Site Specific Costs			NA
Installation Total			19,232,699
Total Direct Capital Cost, DC			45,222,832
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	13,514,869
Total Capital Investment (TCI) = DC + IC			**58,737,702**
Adjusted TCI for Replacment Parts			**57,855,102**
TCI with Retrofit Factor			**75,211,632**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,013,681
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	8,605,244
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,618,924**

Notes & Assumptions

1 Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 March 2009 submittal including anciliary equipment
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
5 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**21,325,238**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,132,524
State Sales Taxes	6.9%	of control device cost (A)	1,466,110
Freight	5%	of control device cost (A)	1,066,262
Purchased Equipment Total (B)	22%		**25,990,134**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,039,605
Handling & erection	50%	of purchased equip cost (B)	12,995,067
Electrical	8%	of purchased equip cost (B)	2,079,211
Piping	1%	of purchased equip cost (B)	259,901
Insulation	7%	of purchased equip cost (B)	1,819,309
Painting	4%	of purchased equip cost (B)	1,039,605
Installation Subtotal Standard Expenses	74%		**19,232,699**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	-
Buildings, as required	N/A	Site Specific	-
Site Specific - Other	N/A	Site Specific	-
Total Site Specific Costs			NA
Installation Total			**19,232,699**
Total Direct Capital Cost, DC			**45,222,832**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,599,013
Construction & field expenses	20%	of purchased equip cost (B)	5,198,027
Contractor fees	10%	of purchased equip cost (B)	2,599,013
Start-up	1%	of purchased equip cost (B)	259,901
Performance test	1%	of purchased equip cost (B)	259,901
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	2,599,013
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**13,514,869**
Total Capital Investment (TCI) = DC + IC			**58,737,702**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**57,855,102**
Total Capital Investment (TCI) with Retrofit Factor	30%		**75,211,632**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr	84,750
Supervisor	15%	15% of Operator Costs	12,713
Maintenance			
Maintenance Labor	60.00	$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr	42,375
Maintenance Materials	100%	of maintenance labor costs	42,375
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization	156,065
Compressed Air	0.47	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization	46,447
N/A			-
SW Disposal	41.32	$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization	50,174
Lime	162.30	$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization	133,302
Filter Bags	242.01	$/bag, 2,952 bags, 5650 hr/yr, 73% utilization	195,479
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,013,681**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	109,328
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,504,233
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	752,116
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	752,116
Capital Recovery	0.0704	for a 20- year equipment life and a 3.5% interest rate	5,487,451
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**8,605,244**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,618,924**

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Capital Recovery Factors

Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	5	years	
CRF	0.2215		
Rep part cost per unit	249.27	$/bag	
Amount Required	2952	# of Bags for new baghouse	
Total Rep Parts Cost	823,565	Cost adjusted for freight & sales tax	
Installation Labor	59,035	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**882,600**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**195,479**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	200,800	10.00			2,053,481	Electricity demand for new baghouse
Total					2,053,481	

Filter Bags

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	290.74	lb/hr Lime
Solid Waste Disposal	1,214	ton/yr unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	73%	Annual Operating Hours		5,650				
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,413	$	84,750	$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr
Supervisor	15%	of Op.			NA	$	12,713	15% of Operator Costs
Maintenance								
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	706	$	42,375	$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$	42,375	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.076	$/kwh	363.4	kW-hr	2,053,481	$	156,065	$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization
Compressed Air	0.467	$/kscf	2	scfm/kacfm	99,384	$	46,447	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization
Water	0.331	$/mgal		gpm				$/mgal, 0 gpm, 5650 hr/yr, 73% utilization
SW Disposal	41.32	$/ton	0.21	ton/hr	1,214	$	50,174	$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization
Lime	162.30	$/ton	290.7	lb/hr	821	$	133,302	$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization
Filter Bags	242.01	$/bag	2,952	bags	N/A	$	195,479	$/bag, 2,952 bags, 5650 hr/yr, 73% utilization

Data Inputs (MPCA FFA Costs, Northshore Mining Company, Boiler 2, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.3

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 765 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,625 Btu/lb

What is the estimated actual annual fuel consumption? 390,484,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.22 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 5.08 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	241	days	Plant Elevation	764	Feet above sea level
Number of days the boiler operates (t_{plant})	241	days			
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.60	lb/MMBtu			
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.45	lb/MMBtu			
Estimated Normalized Stoichiometric Ratio (NSR)	0.79				

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	1.9	$/MMBtu		
Reagent ($Cost_{reag}$)	1.660	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	765	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	776,973,798	lbs/Year	
Actual Annual fuel consumption (Mactual) =		390,484,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.503	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4403	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	114.48	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	252.00	tons/year	1008
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at 764 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.30		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	237	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	474	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	49.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	16,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	17.1	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	227	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.92	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	11.3	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,138,973	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,447,757	in 2019 dollars
Total Capital Investment (TCI) =	$7,262,749	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,138,973	in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,447,757	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$501,394 in 2019 dollars
Indirect Annual Costs (IDAC) =	$514,566 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,015,960 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$108,941 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$364,690 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,337 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$4,168 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$16,045 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$1,214 in 2019 dollars
Direct Annual Cost =		$501,394 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,268 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$511,298 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$514,566 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,015,960 per year in 2019 dollars
NOx Removed =	252 tons/year
Cost Effectiveness =	$4,032 per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Northshore Mining Company, Boiler 2, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.3

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	765	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	8,625	Btu/lb
What is the estimated actual annual fuel consumption?	390,484,000	lbs/year
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	764	Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.22 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ● Method 2
- ○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	241	days
Number of days the boiler operates (t_{plant})	241	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.60	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.12	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	355,523	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.5	Percent	
Reagent ($Cost_{reag}$)	1.660	$/gallon for 50% urea*	* $1.66/gallon is a default value for 50% urea. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0844	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	765	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	776,973,798	lbs/year	
Actual Annual fuel consumption (Mactual) =		390,484,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.503	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4403	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	366.34	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	806.40	tons/year	1008
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	355,523	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	107.02	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)^*$ =	14.3	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.30		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.2373	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,321.88	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	370	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	426	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	20.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	53	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	251	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	502	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	53	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	17,800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0607

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	437.48	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$26,259,107	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,597,326	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$4,999,753	in 2019 dollars
Total Capital Investment (TCI) =	$45,313,042	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$26,259,107 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,597,326 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$4,999,753 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,058,210	in 2019 dollars
Indirect Annual Costs (IDAC) =	$2,754,956	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,813,166	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$226,565	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$386,619	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$162,556	in 2019 dollars
Annual Catalyst Replacement Cost =		$282,469	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$1,058,210	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,454	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,750,502	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,754,956	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,813,166	per year in 2019 dollars
NOx Removed =	806	tons/year
Cost Effectiveness =	$4,729	per ton of NOx removed in 2019 dollars

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Operating Unit: **Power Boiler 2**

Emission Unit Number			Stack/Vent Number		
Design Capacity	765	MMBtu/hr	Standardized Flow Rate	157,508	scfm @ 32º F
Utilization Rate	78%		Exhaust Temperature	265	Deg F
Annual Operating Hours	5,774	hr/yr	Exhaust Moisture Content	11.0%	
Annual Interest Rate	3.50%		Actual Flow Rate	232,100	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	163,800	scfm @ 68º F
Plant Elevation	764	ft	Dry Std Flow Rate	145,700	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**8,933,488**
Purchased Equipment Total (B)	22%	of control device cost (A)	**10,887,688**
Installation - Standard Costs	74%	of purchased equip cost (B)	8,056,889
Installation - Site Specific Costs			N/A
Installation Total			8,056,889
Total Direct Capital Cost, DC			18,944,577
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	5,661,598
Total Capital Investment (TCI) = DC + IC			**23,585,999**
Adjusted TCI for Replacement Parts			23,585,999
Total Capital Investment (TCI) with Retrofit Factor			**30,661,798**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,906,979
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	3,721,546
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,628,525**

Notes & Assumptions

1 Baghouse cost estimate from 2008 vendor data for 165,000 acfm baghouse, (Northshore Mining March 2009 submittal to MPCA)
2 Purchased equipment costs include anciliary equipment
3 Costs scaled up to design airflow using the 6/10 power law
4 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
5 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
6 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**8,933,488**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	893,349
State Sales Taxes	6.9%	of control device cost (A)	614,177
Freight	5%	of control device cost (A)	446,674
Purchased Equipment Total (B)	22%		**10,887,688**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	435,508
Handling & erection	50%	of purchased equip cost (B)	5,443,844
Electrical	8%	of purchased equip cost (B)	871,015
Piping	1%	of purchased equip cost (B)	108,877
Insulation	7%	of purchased equip cost (B)	762,138
Painting	4%	Included in vendor estimate	435,508
Installation Subtotal Standard Expenses	74%		**8,056,889**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**8,056,889**
Total Direct Capital Cost, DC			**18,944,577**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,088,769
Construction & field expenses	20%	of purchased equip cost (B)	2,177,538
Contractor fees	10%	of purchased equip cost (B)	1,088,769
Start-up	1%	of purchased equip cost (B)	108,877
Performance test	1%	of purchased equip cost (B)	108,877
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,088,769
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,661,598**
Total Capital Investment (TCI) = DC + IC			**24,606,175**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**23,585,999**
Total Capital Investment (TCI) with Retrofit Factor	30%		**30,661,798**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr	86,610
Supervisor	0.15	of Op Labor	12,992
Maintenance			
Maintenance Labor	60.00	$/Hr	43,305
Maintenance Materials	100	% of Maintenance Labor	43,305
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization	110,610
N/A			-
Compressed Air	0.47	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization	58,624
N/A			-
Solid Waste Disposal	41.32	$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization	112,208
Trona	285.00	$/ton, 1,501.1 lb/hr, 5774 hr/yr, 78% utilization	963,375
Filter Bags	249.27	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization	225,950
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,906,979**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	111,727
Administration (2% total capital costs)	2%	of total capital costs (TCI)	613,236
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	306,618
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	306,618
Capital Recovery	0.0704	for a 20-year equipment life and a 3.5% interest rate	2,157,397
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**3,721,546**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,628,525**

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Capital Recovery Factors

Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	5	years
CRF	0.2215	
Rep part cost per unit	249.27	$/bag
Amount Required	3412	# of Bags for new baghouse
Total Rep Parts Cost	951,939	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	68,237	20 min per bag
Total Installed Cost	**1,020,177**	
Annualized Cost	**225,950**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	232,100	6.00	1,455,398	Electricity for new baghouse
Total			1,455,398	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	270.18 lb/hr SO2	1501.10 lb/hr Trona	
Solid Waste Disposal	3,481	ton/yr DSI unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	78%	Annual Operating Hours	5,774

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,444	$	86,610	$/Hr, 2.0 hr/8 hr shift, 1,444 hr/yr
Supervisor	15%	of Op Labor			NA	$	12,992	% of Operator Costs
Maintenance								
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	722	$	43,305	$/Hr, 1.0 hr/8 hr shift, 722 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	43,305	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.076	$/kwh	252.1	kW-hr	1,455,398	$	110,610	$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization
Water			N/A	gpm				
Compressed Air	0.467	$/kscf	2.0	scfm/kacfm	125,438	$	58,624	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization
Cooling Water			N/A	gpm				
Solid Waste Disposal	41.32	$/ton	0.6	ton/hr	2,716	$	112,208	$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization
Trona	285.00	$/ton	1,501.1	lb/hr	3,380	$	963,375	$/ton, 1,501.1 lb/hr, 5774 hr/yr, 78% utilization
Filter Bags	249.27	$/bag	3,412	bags	N/A	$	225,950	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Operating Unit: **Power Boiler 2**

Emission Unit Number	EQUI 15 / EU 002		Stack/Vent Number	SV 002	
Design Capacity	765	MMBtu/hr	Standardized Flow Rate	157,508	scfm @ 32º F
Utilization Rate	78%		Temperature	265	Deg F
Annual Operating Hours	5,774	Hours	Moisture Content	11.0%	
Annual Interest Rate	3.5%		Actual Flow Rate	232,100	acfm
Equipment Life	20	yrs	Standardized Flow Rate	163,800	scfm @ 68º F
			Dry Std Flow Rate	145,700	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**22,495,853**
Purchased Equipment Total (B)	22%	of control device cost (A)	**27,416,821**
Installation - Standard Costs	74%	of purchased equip cost (B)	20,288,447
Installation - Site Specific Costs			NA
Installation Total			20,288,447
Total Direct Capital Cost, DC			47,705,268
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	14,256,747
Total Capital Investment (TCI) = DC + IC			**61,962,015**
Adjusted TCI for Replacment Parts			**60,941,838**
TCI with Retrofit Factor			**79,224,390**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,140,905
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	9,080,966
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,221,871**

Notes & Assumptions

1 Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 March 2009 submittal including anciliary equipment
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
5 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**22,495,853**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,249,585
State Sales Taxes	6.9%	of control device cost (A)	1,546,590
Freight	5%	of control device cost (A)	1,124,793
Purchased Equipment Total (B)	22%		**27,416,821**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,096,673
Handling & erection	50%	of purchased equip cost (B)	13,708,410
Electrical	8%	of purchased equip cost (B)	2,193,346
Piping	1%	of purchased equip cost (B)	274,168
Insulation	7%	of purchased equip cost (B)	1,919,177
Painting	4%	of purchased equip cost (B)	1,096,673
Installation Subtotal Standard Expenses	74%		**20,288,447**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	-
Buildings, as required	N/A	Site Specific	-
Site Specific - Other	N/A	Site Specific	-
Total Site Specific Costs			NA
Installation Total			**20,288,447**
Total Direct Capital Cost, DC			**47,705,268**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,741,682
Construction & field expenses	20%	of purchased equip cost (B)	5,483,364
Contractor fees	10%	of purchased equip cost (B)	2,741,682
Start-up	1%	of purchased equip cost (B)	274,168
Performance test	1%	of purchased equip cost (B)	274,168
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	2,741,682
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**14,256,747**
Total Capital Investment (TCI) = DC + IC			**61,962,015**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**60,941,838**
Total Capital Investment (TCI) with Retrofit Factor	30%		**79,224,390**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	\$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr	86,610
Supervisor	15%	15% of Operator Costs	12,992
Maintenance			
Maintenance Labor	60.00	\$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr	43,305
Maintenance Materials	100%	of maintenance labor costs	43,305
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	\$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization	184,350
Compressed Air	0.47	\$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization	58,624
N/A			-
SW Disposal	41.32	\$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization	64,474
Lime	162.30	\$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization	171,295
Filter Bags	242.01	\$/bag, 3,412 bags, 5774 hr/yr, 78% utilization	225,950
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,140,905**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	111,727
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,584,488
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	792,244
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	792,244
Capital Recovery	0.0704	for a 20- year equipment life and a 3.5% interest rate	5,800,264
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**9,080,966**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,221,871**

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Capital Recovery Factors

Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	5	years	
CRF	0.2215		
Rep part cost per unit	249.27	$/bag	
Amount Required	3412	# of Bags for new baghouse	
Total Rep Parts Cost	951,939	Cost adjusted for freight & sales tax	
Installation Labor	68,237	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**1,020,177**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**225,950**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	232,100	10.00			2,425,663	Electricity demand for new baghouse
Total					2,425,663	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	365.58 lb/hr Lime
Solid Waste Disposal	1,560	ton/yr unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	78%	Annual Operating Hours		5,774			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,444	$ 86,610	$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr
Supervisor	15%	of Op.			NA	$ 12,992	15% of Operator Costs
Maintenance							
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	722	$ 43,305	$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$ 43,305	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.076	$/kwh	420.1	kW-hr	2,425,663	$ 184,350	$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization
Compressed Air	0.467	$/kscf	2	scfm/kacfm	125,438	$ 58,624	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization
Water	0.331	$/mgal		gpm			$/mgal, 0 gpm, 5774 hr/yr, 78% utilization
SW Disposal	41.32	$/ton	0.27	ton/hr	1,560	$ 64,474	$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization
Lime	162.30	$/ton	365.6	lb/hr	1,055	$ 171,295	$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization
Filter Bags	242.01	$/bag	3,412	bags	N/A	$ 225,950	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization

Data Inputs (MPCA FFA Costs, Sappi Cloquet, Boiler 9, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 430 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 4,597 Btu/lb

What is the estimated actual annual fuel consumption? 517,045,435 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 0.05 percent by weight

or

Select the appropriate SO_2 emission rate: < 3lb/MMBtu

Ash content (%Ash): 2.8 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	352	days
Number of days the boiler operates (t_{plant})	352	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.292	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.219	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	3.02	

Plant Elevation	1083	Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	1.9	$/MMBtu		
Reagent ($Cost_{reag}$)	0.554	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.74	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	13.60	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	Select type of coal	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	430	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	819,334,091	lbs/Year
Actual Annual fuel consumption (Mactual) =		517,045,435	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.631	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5528	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	31.39	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	86.76	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at 1083 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.1	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

347.05 pre-control TPY

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	141	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	485	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	64.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	21,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	17.9	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	110	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.14	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	6.9	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$6,068,270	in 2022 dollars (site specific quotes)
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$0	in 2019 dollars
Total Capital Investment (TCI) =	$6,068,270	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$0	in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$0	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$312,950	in 2019 dollars
Indirect Annual Costs (IDAC) =	$429,937	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$742,887	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$91,024	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$198,159	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$8,328	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,544	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$11,960	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$935	in 2019 dollars
Direct Annual Cost =		$312,950	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,731	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$427,206	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$429,937	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$742,887	per year in 2019 dollars
NOx Removed =	87	tons/year
Cost Effectiveness =	$8,562	per ton of NOx removed in 2019 dollars

Class 3 Estimate for SNCR System on #9 Boiler

	SNCR Installation for #9 Boiler	Cost Estimate
1	Equipment & Engineering (Jansen)	$2,271,000
3	Piping Labor (Jamar)	$601,302
4	Setting Skids & Tank Labor (Jamar)	$138,762
5	Install Steel Labor (Jamar)	$154,180
6	Install Tube Bends Labor (Jamar)	$231,270
7	Piping Tie-ins Labor (Jamar)	$231,270
8	Piping Relocations Labor (Jamar)	$154,180
9	Sheetmetal Flashing Labor (Jamar)	$30,836
10	Pipe Fitter Materials & Consumables (Jamar)	$166,462
11	Pipe Fitter Tools & Equipment (Jamar)	$178,738
12	Insulation (Jamar)	$83,750
13	Concrete Bases & Floor (Jamar)	$212,500
14	Scaffolding (Jamar)	$25,000
15	Refractory for Tube Bends (Jamar)	$9,372
16	Crane Rental (Jamar)	$191,670
17	Electrical Wiring Labor (Hunt)	$96,000
18	Electrical Wiring Materials (Hunt)	$51,000
19	Electrical Contingency (Hunt)	$15,300
20	Project Engineering (Sappi)	$484,259
21	Owners Cost (Sappi)	$257,159
25	Contingency	$484,259
	Total	**$6,068,270**

Data Inputs (MPCA FFA Costs, Sappi Cloquet, Boiler 9, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.33

* NOTE: You must document why a retrofit factor of 1.33 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	430	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	4,597	Btu/lb
What is the estimated actual annual fuel consumption?	517,045,435	lbs/Year
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 1083 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 0.05 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Parameter	Value	Units
Number of days the SCR operates (t_{SCR})	352	days
Number of days the boiler operates (t_{plant})	352	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.292	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.058	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

80.0% Assumed Control efficiency

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Parameter	Value	Units
Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Parameter	Value	Units
Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours
Estimated SCR equipment life	25	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Parameter	Value	Units
Gas temperature at the SCR inlet (T)	413	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	547	ft^3/min-MMBtu/hour

Parameter	Value	Units
Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Parameter	Value	Units / Notes
Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI
Annual Interest Rate (i)	3.5	Percent
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0844	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	430	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	819,403,959	lbs/Year	
Actual Annual fuel consumption (Mactual) =		517,045,435	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.631	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5528	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	100.45	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	277.62	tons/year	347.02125
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	177,016	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	33.83	/hour	
Residence Time	$1/V_{space}$	0.03	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.33		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.4914	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	5,232.59	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	184	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	10	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	212	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	14.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	79	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	39	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	135	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	18	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	6,100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0607

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	247.91	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$16,277,179	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,663,198	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$4,094,935	in 2019 dollars
Total Capital Investment (TCI) =	$29,945,905	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$16,277,179	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,663,198	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$4,094,935	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$514,973	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,822,048	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,337,020	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$149,730	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$55,026	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$115,656	in 2019 dollars
Annual Catalyst Replacement Cost =		$194,561	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$514,973	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,331	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,817,716	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,822,048	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,337,020	per year in 2019 dollars
NOx Removed =	278	tons/year
Cost Effectiveness =	$8,418	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Southern Minnesota Beet Sugar Cooperative, Boiler 1, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 472.4 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,999 Btu/lb

What is the estimated actual annual fuel consumption? 342,550,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.28 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 5.84 percent by weight

*The ash content of 5.84% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	314	days
Number of days the boiler operates (t_{plant})	314	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.59	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.3	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.57	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 1100 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019).

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5	Percent		
Fuel ($Cost_{fuel}$)	1.89	\$/MMBtu*		
Reagent ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	\$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	\$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	\$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	472	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	459,863,227	lbs/Year	
Actual Annual fuel consumption (Mactual) =		342,550,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.745	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	6525	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	49	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	136.89	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	446.62	tons/year	909
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at 1100 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.1	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	285	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	569	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	60.0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	20,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	20.5	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	273	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	2.31	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	15.0	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,040,438 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,466,690 in 2019 dollars
Total Capital Investment (TCI) =	$7,159,267 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,040,438 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,466,690 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$806,838	in 2019 dollars
Indirect Annual Costs (IDAC) =	$507,234	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,314,072	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$107,389	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$649,903	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$11,292	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$7,427	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$28,444	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$2,383	in 2019 dollars
Direct Annual Cost =		$806,838	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,222	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$504,012	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$507,234	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,314,072	per year in 2019 dollars
NOx Removed =	447	tons/year
Cost Effectiveness =	$2,942	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Southern Minnesota Beet Sugar Cooperative, Boiler 1, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 472.4 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,999 Btu/lb

What is the estimated actual annual fuel consumption? 342,550,000 lbs/Year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1100 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.28 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ● Method 2
- ○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	314	days
Number of days the boiler operates (t_{plant})	314	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.59	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	209000	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI
Annual Interest Rate (i)	3.5	Percent
Reagent ($Cost_{reag}$)	1.660	$/gallon for 50% urea*
Electricity ($Cost_{elect}$)	0.0844	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	67.53	$/hour (including benefits)
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* $1.66/gallon is a default value for 50% urea. User should enter actual value, if known.

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	472	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	459,863,227	lbs/Year
Actual Annual fuel consumption (Mactual) =		342,550,000	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.745	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6525	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	91.5	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_B$ =	254.99	lb/hour
Total NO_x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000$ =	831.94	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.14	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	209,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	91.98	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.1	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

909

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3219	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,272.17	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	218	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	250	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	15.8	feet
Reactor height =	$(R_{layer}$ + $R_{empty})$ x (7ft + h_{layer}) + 9ft	55	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	175	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	349	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	37	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	12,400	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0704

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	270.15	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$20,221,322	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,791,299	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$4,769,432	in 2019 dollars
Total Capital Investment (TCI) =	$37,416,668	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$20,221,322 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,791,299 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$4,769,432 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$926,643 in 2019 dollars
Indirect Annual Costs (IDAC) =	$2,638,923 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,565,566 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$187,083 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$398,862 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$148,782 in 2019 dollars
Annual Catalyst Replacement Cost =		$191,915 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$926,643 in 2019 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,790 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,634,133 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,638,923 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,565,566 per year in 2019 dollars
NOx Removed =	832 tons/year
Cost Effectiveness =	$4,286 per ton of NOx removed in 2019 dollars

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 4: NO_x Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25		**Chemical Engineering**	
Desgin Capacity	472	MMBTU/hr	Standardized Flow Rate	123,889	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utilization Rate	100%		Temperature	370	Deg F	1998/1999	390
Expected Annual Hours of Operation	6,525	Hours	Moisture Content	11.8%		2019	607.5
Annual Interest Rate	3.5%		Actual Flow Rate	209,000	acfm	Inflation Adj	1.56
Expected Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F		
			Dry Std Flow Rate	117,332	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			635,318
Purchased Equipment Total (B)	22%	of control device cost (A)	**774,294**
Installation - Standard Costs	30%	of purchased equip cost (B)	232,288
Installation - Site Specific Costs			NA
Installation Total			232,288
Total Direct Capital Cost, DC			1,006,582
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	294,232
Total Capital Investment (TCI) = DC + IC			**1,300,814**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,145,260
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	268,953
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,414,213**

Notes & Assumptions
1 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**635,318**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	63,532
MN Sales Taxes	6.9%	of control device cost (A)	43,678
Freight	5%	of control device cost (A)	31,766
Purchased Equipment Total (B)	22%		**774,294**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	61,944
Handling & erection	14%	of purchased equip cost (B)	108,401
Electrical	4%	of purchased equip cost (B)	30,972
Piping	2%	of purchased equip cost (B)	15,486
Insulation	1%	of purchased equip cost (B)	7,743
Painting	1%	of purchased equip cost (B)	7,743
Installation Subtotal Standard Expenses	30%		**232,288**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**232,288**
Total Direct Capital Cost, DC			**1,006,582**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	77,429
Construction & field expenses	5%	of purchased equip cost (B)	38,715
Contractor fees	10%	of purchased equip cost (B)	77,429
Start-up	2%	of purchased equip cost (B)	15,486
Performance test	1%	of purchased equip cost (B)	7,743
Model Studies		of purchased equip cost (B)	0
Contingencies	10%	of purchased equip cost (B)	77,429
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	**294,232**
Total Capital Investment (TCI) = DC + IC			**1,300,814**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,300,814**
Total Capital Investment (TCI) with Retrofit Factor	50%		**1,951,221**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	69.56	$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr	28,367
Supervisor	15%	15% of Operator Costs	4,255
Maintenance			
Maintenance Labor	69.56	$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr	28,367
Maintenance Materials	100%	of maintenance labor costs	28,367
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 774 kW-hr, 6525.28365791702 hr/yr, 100% utilization	402,205
Natural Gas	3.90	$/mscf, 428 scfm, 6525.28365791702 hr/yr, 100% utilization	653,699
Total Annual Direct Operating Costs			**1,145,260**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	53,614
Administration (2% total capital costs)	2%	of total capital costs (TCI)	39,024
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	19,512
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	19,512
Capital Recovery	0.0704	for a 20- year equipment life and a 3.5% interest rate	137,290
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**268,953**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,414,213**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

Capital Recovery Factors		
Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Catalyst:	**Catalyst**	
Equipment Life	3	years
CRF	0.3569	
Rep part cost per unit	0	$/ft^3
Amount Required	39	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3569		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	209,000		19	0.6		774.3	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	209,000		23	0.6		937.4	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				774.3	

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations — **Annual hours of operation:** **6,525**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	69.56	$/Hr	0.5	hr/8 hr shift	408	28,367	$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr
Supervisor	15%	of Op.			NA	4,255	15% of Operator Costs
Maintenance							
Maint Labor	69.56	$/Hr	0.5	hr/8 hr shift	408	28,367	$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	28,367	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	774.3	kW-hr	5,052,821	402,205	$/kwh, 774 kW-hr, 6525.28365791702 hr/yr, 100% utilization
Natural Gas	3.90	$/mscf	428	scfm	167,615	653,699	$/mscf, 428 scfm, 6525.28365791702 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	370	Deg F - Temperature of waste gas into heat recovery
T_{fi}	650	Deg F - Temperature of Flue gas into heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	566	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	454	Deg F - Temperature of flue gas out of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
ρ_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
ρ_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	132,954	scfm - Flow of waste gas
Q_{af}	428	scfm - Flow of auxiliary fuel

Year 2005 Inflation Rate 3.0%

Cost Calculations 133,382 scfm Flue Gas Cost in 1989 $'s $407,859

Current Cost Using CHE Plant Cost Index $635,318

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Indurator Flue Gas Heat Capacity - Basis Typical Composition

		100 scfm	359 scf/lbmole			
		Gas Composition	lb/hr f	wt %	Cp Gas	Cp Flue
28	mw CO	0 v %	0			
44	mw CO2	15 v %	184	22.0%	0.24	0.0528
18	mw H2O	10 v %	50	6.0%	0.46	0.0276
28	mw N2	60 v %	468	56.0%	0.27	0.1512
32	mw O2	15 v %	134	16.0%	0.23	0.0368
	Cp Flue Gas	100 v %	836	100.0%		0.2684

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 6: NO_x Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Desgin Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	370	Deg F
Expected Annual Hours of Operation	6,525	Hours	Moisture Content	11.8%	
Annual Interest Rate	3.5%		Actual Flow Rate	209,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**1,265,871**
Purchased Equipment Total (B)	22%	of control device cost (A)	**1,542,780**
Installation - Standard Costs	0%	of purchased equip cost (B)	1,215,900
Installation - Site Specific Costs			0
Installation Total			1,215,900
Total Direct Capital Cost, DC			2,758,680
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	802,246
Total Capital Investment (TCI) = DC + IC			**3,560,926**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	89,357
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	643,095
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**732,452**

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Cont. Emis. lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	909.0	179.5	**0.38**	585.7	323.3	2,265
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1 Purchased equipment and installation costs from vendor
2 Assumed 0.5 hr/shift operatior and maintenance labor for LNB
3 Controlled emission factor based on vendor estimated burner/OFA performance

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 6: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		**1,265,871**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC		
Instrumentation	10% of control device cost (A)	126,587
MN Sales Taxes	6.9% of control device cost (A)	87,029
Freight	5% of control device cost (A)	63,294
Purchased Equipment Total (B)	22%	**1,542,780**
Installation [1]		
Foundations & supports	0% of purchased equip cost (B)	0
Handling & erection	0% of purchased equip cost (B)	0
Electrical	0% of purchased equip cost (B)	0
Piping	0% of purchased equip cost (B)	0
Insulation	0% of purchased equip cost (B)	0
Painting	0% of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	0%	**1,215,900**
Installation Total		**1,215,900**
Total Direct Capital Cost, DC		**2,758,680**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	154,278
Construction & field expenses	20% of purchased equip cost (B)	308,556
Contractor fees	10% of purchased equip cost (B)	154,278
Start-up	1% of purchased equip cost (B)	15,428
Performance test	1% of purchased equip cost (B)	15,428
Model Studies	NA of purchased equip cost (B)	NA
Contingencies	10% of purchased equip cost (B)	154,278
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**802,246**
Total Capital Investment (TCI) = DC + IC		**3,560,926**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Site Specific - Other	Site Specific	
Total Site Specific Costs		**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**3,560,926**
Total Capital Investment (TCI) with Retrofit Factor	50%	**5,341,389**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	69.56 $/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr	28,367
Supervisor	15% 15% of Operator Costs	4,255
Maintenance (2)		
Maintenance Labor	69.56 $/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr	28,367
Maintenance Materials	100% of maintenance labor costs	28,367
Utilities, Supplies, Replacements & Waste Management		
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Total Annual Direct Operating Costs		**89,357**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	53,614
Administration (2% total capital costs)	2% of total capital costs (TCI)	106,828
Property tax (1% total capital costs)	1% of total capital costs (TCI)	53,414
Insurance (1% total capital costs)	1% of total capital costs (TCI)	53,414
Capital Recovery	7% for a 20- year equipment life and a 3.5% interest rate	375,826
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**643,095**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**732,452**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 6: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Capital Recovery Factors		
Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations — **Annual hours of operation:** **6,525** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	69.56	$/Hr	0.5	hr/8 hr shift	408	28,367	$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr
Supervisor	15%	of Op.			NA	4,255	15% of Operator Costs
Maintenance							
Maint Labor	69.56	$/Hr	0.5	hr/8 hr shift	408	28,367	$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	28,367	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 6525.28365791702 hr/yr, 100% utilization
Natural Gas	3.90	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 6525.28365791702 hr/yr, 100% utilization
Water	5.28	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 6525.28365791702 hr/yr, 100% utilization

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Design Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Utilization Rate	100%		Temperature	370	Deg F
Annual Operating Hours	6,525	Hours	Moisture Content	11.8%	
Annual Interest Rate	3.5%		Actual Flow Rate	209,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**13,364,399**
Purchased Equipment Total (B)	22%	of control device cost (A)	**16,287,862**
Installation - Standard Costs	74%	of purchased equip cost (B)	12,053,018
Installation - Site Specific Costs			NA
Installation Total			12,053,018
Total Direct Capital Cost, DC			28,340,879
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	8,469,688
Total Capital Investment (TCI) = DC + IC			**36,810,567**
Adjusted TCI for Replacment Parts			**36,347,289**
TCI with Retrofit Factor			**54,520,933**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	958,329
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	6,265,971
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,224,301**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		795.0	90%			79.5	715.5	10,097
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1. Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 2006 BART submittal including anciliary equipment
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [(1)]			**13,364,399**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,336,440
State Sales Taxes	6.9%	of control device cost (A)	918,802
Freight	5%	of control device cost (A)	668,220
Purchased Equipment Total (B)	22%		**16,287,862**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	651,514
Handling & erection	50%	of purchased equip cost (B)	8,143,931
Electrical	8%	of purchased equip cost (B)	1,303,029
Piping	1%	of purchased equip cost (B)	162,879
Insulation	7%	of purchased equip cost (B)	1,140,150
Painting	4%	of purchased equip cost (B)	651,514
Installation Subtotal Standard Expenses	74%		**12,053,018**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	-
Buildings, as required	N/A	Site Specific	-
Site Specific - Other	N/A	Site Specific	-
Total Site Specific Costs			NA
Installation Total			**12,053,018**
Total Direct Capital Cost, DC			**28,340,879**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,628,786
Construction & field expenses	20%	of purchased equip cost (B)	3,257,572
Contractor fees	10%	of purchased equip cost (B)	1,628,786
Start-up	1%	of purchased equip cost (B)	162,879
Performance test	1%	of purchased equip cost (B)	162,879
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,628,786
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**8,469,688**
Total Capital Investment (TCI) = DC + IC			**36,810,567**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**36,347,289**
Total Capital Investment (TCI) with Retrofit Factor	50%		**54,520,933**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	69.56	$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr	113,469
Supervisor	15%	15% of Operator Costs	17,020
Maintenance			
Maintenance Labor	69.56	$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr	56,734
Maintenance Materials	100%	of maintenance labor costs	56,734
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 436.9 kW-hr, 6525.28365791702 hr/yr, 100% utilization	226,923
Compressed Air	0.50	$/kscf, 2.0 scfm/kacfm, 6525.28365791702 hr/yr, 100% utilizat	81,142
N/A			-
15% of Operator Costs	65.24	$/ton, 0.2 ton/hr, 6525.28365791702 hr/yr, 100% utilization	102,545
0	189.19	$/ton, 282.2 lb/hr, 6525.28365791702 hr/yr, 100% utilization	201,154
$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr	234.86	$/bag, 1,620 bags, 6525.28365791702 hr/yr, 100% utilization	102,608
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**958,329**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	146,375
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,090,419
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	545,209
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	545,209
Capital Recovery	0.0704	for a 20- year equipment life and a 3.5% interest rate	3,938,759
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,265,971**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,224,301**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Capital Recovery Factors

Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Parts & Equipment:	Filter Bags		
Equipment Life	5	years	
CRF	0.2215		
Rep part cost per unit	234.86	$/bag	
Amount Required	1620		
Total Rep Parts Cost	425,718	Cost adjusted for freight & sales tax	
Installation Labor	37,560	20 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**463,278**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**102,608**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	209,000	10.00			2,850,793	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					2,850,793	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	282.17	lb/hr Lime
Solid Waste Disposal	1,572	ton/yr unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		6,525				
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	69.56	$/Hr	2.0	hr/8 hr shift	1,631	$	113,469	$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr
Supervisor	15%	of Op.			NA	$	17,020	15% of Operator Costs
Maintenance								
Maint Labor	69.56	$/Hr	1.0	hr/8 hr shift	816	$	56,734	$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$	56,734	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.080	$/kwh	436.9	kW-hr	2,850,793	$	226,923	$/kwh, 436.9 kW-hr, 6525.28365791702 hr/yr, 100% utilization
Compressed Air	0.496	$/kscf	2	scfm/kacfm	163,654	$	81,142	$/kscf, 2.0 scfm/kacfm, 6525.28365791702 hr/yr, 100% utilization
$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr	5.282	$/mgal		gpm				$/mgal, 0 gpm, 6525.28365791702 hr/yr, 100% utilization
15% of Operator Costs	65.24	$/ton	0.24	ton/hr	1,572	$	102,545	$/ton, 0.2 ton/hr, 6525.28365791702 hr/yr, 100% utilization
	189.19	$/ton	282.2	lb/hr	1,063	$	201,154	$/ton, 282.2 lb/hr, 6525.28365791702 hr/yr, 100% utilization
$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr	234.86	$/bag	1,620	bags	N/A	$	102,608	$/bag, 1,620 bags, 6525.28365791702 hr/yr, 100% utilization
100% of Maintenance Labor								

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Operating Unit: **Boiler 1**

Emission Unit Number			Stack/Vent Number		
Design Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	370	Deg F
Annual Operating Hours	6,525	hr/yr	Exhaust Moisture Content	11.8%	
Annual Interest Rate	3.50%		Actual Flow Rate	209,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
Plant Elevation	1100	ft	Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**9,306,454**
Purchased Equipment Total (B)	22%	of control device cost (A)	**11,342,240**
Installation - Standard Costs	74%	of purchased equip cost (B)	8,393,258
Installation - Site Specific Costs			N/A
Installation Total			8,393,258
Total Direct Capital Cost, DC			19,735,498
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	5,897,965
Total Capital Investment (TCI) = DC + IC			**25,170,184**
Adjusted TCI for Replacement Parts			25,170,184
Total Capital Investment (TCI) with Retrofit Factor			**37,755,277**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,870,007
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	4,415,695
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,285,702**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/Ton Rem
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	243.67	795.00	70%	238.50	556.50	$11,295
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 2006 BART submittal including anciliary equipment
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**9,306,454**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	930,645
State Sales Taxes	6.9%	of control device cost (A)	639,819
Freight	5%	of control device cost (A)	465,323
Purchased Equipment Total (B)	22%		**11,342,240**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	453,690
Handling & erection	50%	of purchased equip cost (B)	5,671,120
Electrical	8%	of purchased equip cost (B)	907,379
Piping	1%	of purchased equip cost (B)	113,422
Insulation	7%	of purchased equip cost (B)	793,957
Painting	4%	Included in vendor estimate	453,690
Installation Subtotal Standard Expenses	74%		**8,393,258**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**8,393,258**
Total Direct Capital Cost, DC			**19,735,498**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,134,224
Construction & field expenses	20%	of purchased equip cost (B)	2,268,448
Contractor fees	10%	of purchased equip cost (B)	1,134,224
Start-up	1%	of purchased equip cost (B)	113,422
Performance test	1%	of purchased equip cost (B)	113,422
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,134,224
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,897,965**
Total Capital Investment (TCI) = DC + IC			**25,633,463**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**25,170,184**
Total Capital Investment (TCI) with Retrofit Factor	50%		**37,755,277**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	69.56	$/Hr	113,469
Supervisor	0.15	of Op Labor	17,020
Maintenance			
Maintenance Labor	69.56	$/Hr	56,734
Maintenance Materials	100	% of Maintenance Labor	56,734
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 262.1 kW-hr, 6525.28365791702 hr/yr, 100% utilizati	136,154
N/A			-
Compressed Air	0.50	$/kscf, 2.0 scfm/kacfm, 6525.28365791702 hr/yr, 100% utiliz	81,142
N/A			-
Solid Waste Disposal	65.24	$/ton, 0.5 ton/hr, 6525.28365791702 hr/yr, 100% utilization	228,801
Trona	285.00	$/ton, 1,158.6 lb/hr, 6525.28365791702 hr/yr, 100% utilizatio	1,077,345
Filter Bags	234.86	$/bag, 1,620 bags, 6525.28365791702 hr/yr, 100% utilizatior	102,608
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,870,007**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	146,375
Administration (2% total capital costs)	2%	of total capital costs (TCI)	755,106
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	377,553
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	377,553
Capital Recovery	0.0704	for a 20-year equipment life and a 3.5% interest rate	2,656,502
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**4,415,695**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,285,702**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Capital Recovery Factors

Primary Installation		
Interest Rate	3.50%	
Equipment Life	20	years
CRF	0.0704	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	5	years
CRF	0.2215	
Rep part cost per unit	234.86	$/bag
Amount Required	1620	Bags
Total Rep Parts Cost	425,718	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	37,560	20 min per bag
Total Installed Cost	**463,278**	
Annualized Cost	**102,608**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	209,000	6.00	1,710,476	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			1,710,476	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	243.67 lb/hr SO2	1158.62 lb/hr Trona	
Solid Waste Disposal	3,507	ton/yr DSI unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		6,525			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	69.56	$/Hr	2.0	hr/8 hr shift	1,631	$ 113,469	$/Hr, 2.0 hr/8 hr shift, 1,631 hr/yr
Supervisor	15%	of Op Labor			NA	$ 17,020	% of Operator Costs
Maintenance							
Maint Labor	69.56	$/Hr	1.0	hr/8 hr shift	816	$ 56,734	$/Hr, 1.0 hr/8 hr shift, 816 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 56,734	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	262.1	kW-hr	1,710,476	$ 136,154	$/kwh, 262.1 kW-hr, 6525.28365791702 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.496	$/kscf	2.0	scfm/kacfm	163,654	$ 81,142	$/kscf, 2.0 scfm/kacfm, 6525.28365791702 hr/yr, 100% utilizati
Cooling Water			N/A	gpm			
Solid Waste Disposal	65.24	$/ton	0.5	ton/hr	3,507	$ 228,801	$/ton, 0.5 ton/hr, 6525.28365791702 hr/yr, 100% utilization
Trona	285.00	$/ton	1,158.6	lb/hr	3,780	$ 1,077,345	$/ton, 1,158.6 lb/hr, 6525.28365791702 hr/yr, 100% utilization
Filter Bags	234.86	$/bag	1,620	bags	N/A	$ 102,608	$/bag, 1,620 bags, 6525.28365791702 hr/yr, 100% utilization

Data Inputs (MPCA FFA Costs, Virginia Department of Public Utilities, Boiler 7, SNCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 175 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,625 Btu/lb

What is the estimated actual annual fuel consumption? 42,518,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.32 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 5 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	211	days
Number of days the boiler operates (t_{plant})	211	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.386	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.232	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

Plant Elevation	1440	Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7 2016 CEPCI
Annual Interest Rate (i)	3.5	Percent	
Fuel ($Cost_{fuel}$)	1.9	\$/MMBtu	
Reagent ($Cost_{reag}$)	0.554	\$/gallon for a 29 percent solution of ammonia	
Water ($Cost_{water}$)	0.0042	\$/gallon*	
Electricity ($Cost_{elect}$)	0.0844	\$/kWh	
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	\$/ton*	

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	(1.90 $/MMBtu) U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	175	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	177,739,130	lbs/Year	
Actual Annual fuel consumption (Mactual) =		42,518,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.239	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	2096	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	40	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	27.02	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	28.31	tons/year	70.776526
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05		
Atmospheric pressure at 1440 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.0	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	26	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	91	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	12.1	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	4,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0704

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	3.3	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	21	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.21	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1\text{x}10^6)/HHV$ =	1.2	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$907,552 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,370,699 in 2019 dollars
Total Capital Investment (TCI) =	$2,961,727 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$907,552 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,370,699 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$60,134	in 2019 dollars
Indirect Annual Costs (IDAC) =	$209,838	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$269,972	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$44,426	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$14,028	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$590	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$180	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$847	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$63	in 2019 dollars
Direct Annual Cost =		$60,134	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,333	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$208,506	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$209,838	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$269,972	per year in 2019 dollars
NOx Removed =	28	tons/year
Cost Effectiveness =	$9,536	per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Virginia Department of Public Utilities, Boiler 7, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 175 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,625 Btu/lb

What is the estimated actual annual fuel consumption? 42,518,000 lbs/year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1440 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.32 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Parameter	Value	Units
Number of days the SCR operates (t_{SCR})	211	days
Number of days the boiler operates (t_{plant})	211	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.39	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.06	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Parameter	Value	Units
Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Parameter	Value	Units
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Parameter	Value	Units
Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Parameter	Value	Units
Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Parameter	Value	Units / Notes
Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI
Annual Interest Rate (i)	3.5	Percent
Reagent ($Cost_{reag}$)	0.554	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0844	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	175	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	177,739,130	lbs/year	
Actual Annual fuel consumption (Mactual) =		42,518,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.239	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2096	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	85.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	57.42	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	60.16	tons/year	70.776526
NO_x removal factor (NRF) =	EF/80 =	1.06		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	86,408	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	115.69	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.0	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.1865	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	746.88	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	90	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}))$ + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	104	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	10.2	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	22	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	77	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	10	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,500	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0607

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	100.08	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$5,393,867	in 2019 dollars
Reagent Preparation Cost (RPC) =	$1,741,116	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$2,121,362	in 2019 dollars
Total Capital Investment (TCI) =	$12,033,247	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$5,393,867	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$1,741,116	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,121,362	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$100,330 in 2019 dollars
Indirect Annual Costs (IDAC) =	$732,659 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$832,990 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$60,166 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$11,924 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$17,700 in 2019 dollars
Annual Catalyst Replacement Cost =		$10,540 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}/R_{layer}$) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$100,330 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,241 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$730,418 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$732,659 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$832,990 per year in 2019 dollars
NOx Removed =	60 tons/year
Cost Effectiveness =	$13,846 per ton of NOx removed in 2019 dollars

Data Inputs (MPCA FFA Costs, Virginia Department of Public Utilities, Boiler 7, Dry Scrubber, 2022-02-14)

Enter the following data for your combustion unit:

Is the FGD for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor. Enter 1 for projects of average difficulty. Enter values >1 for more difficult retrofits and enter <1 for less difficult retrofits. 1

Directions: Enter data in highlighted data fields.

What is the gross MW rating at full load capacity (A)? 8.24 MW

Provide the following information for the coal burned:

Select type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) percent by weight **OR** SO_2 Emissions (SO_{2in}) 0.50 lb/MMBtu

Oulet SO_2 Emissions (SO_{2out}) 0.10 lb/MMBtu

What is the higher heating value of the fuel (HHV)? Btu/lb

*HHV is the weighted average value calculated using the values entered in the coal blend composition table.

*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in lb/MMBtu above

What is the estimated actual annual MWh output? 12,466 MWh

Waste from a WFDG system disposed in an onsite or offsite landfill? Offsite Landfill

Gross heat input rate (GHR) 21.24 MMBtu/MWh

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t_{ABS})	4380	Hours	Plant Elevation	1440 Feet above sea level
Number of hours the boiler operates (t_{plant})	4380	Hours		

Number of Full Time Operators (FT):

SDA System	1	
WFGD system	1.5	

Estimated equipment life:

SDA System	30	Years
Wet FGD System	30	Years
Estimated equipment life for mercury monitor for wastewater treatment system for Wet FGD Systems	6	Years

Enter the cost data for the proposed FGD System:

Desired dollar-year for Capital Costs	2020			
CEPCI for 2020	592.1	Enter the CEPCI value for 2020	541.7	2016 CEPCI*
Annual Interest Rate (i)	3.25	Percent**	** 3.25 percent is the default bank prime rate. User should enter current bank prime rate (available at	

Sorbent Cost:

Lime (for SDA)	125.00	$/ton of Lime
Limestone (for Wet FGD)	30.00	$/ton of Limestone
Water ($Cost_{water}$)	0.0042	$/gallon
Electricity ($Cost_{elect}$)	0.0361	$/kWh*
Waste Disposal cost ($Cost_{waste}$)	30.00	$/ton
Labor Rate	60.00	$/hour
Purchase Equipment Cost for Mercury Monitor for wastewater treatment System (MMCost)	100,000	$/monitor

*Note: CEPCI = Chemical Engineering Plant Cost Index. The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used
Lime ($/ton)	125	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Limestone ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Water Cost ($/gallon)	0.00420	Average water rates for industrial facilities (compiled by Black & Veatch. See '50 Largest Cities Water/Wastewater Rate Survey - 2018-2019.'Available at www.bv.com/sites/default/files/2019-10/50_Largest_Cities_Rate_Survey_2018_2019_Report.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf	
Waste Disposal Cost ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Higher Heating Value (HHV) (Btu/lb)	8,826	Average HHV based 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Average Sulfur Content (%)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate March 2, 2021 (available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/).	
Hourly Labor Rate ($/hour)	60	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

Dry FGD Design Parameters

The following design parameters for the dry FGD system were calculated based on the values entered on the *FGD Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	A x GHR =	175	MMBtu/hour
Maximum Annual MWh Output (B_{MW}) =	A x 8760 =	72,182	MWh
Estimated Actual Annual MWh Output (B_{output}) =	Value entered by user	12,466	MWh
Heat Rate Factor (HRF) =	Gross Plant Heat Rate/10 =	2.12	
Total System Capacity Factor (CF_{total}) =	$(B/B_{mw})*(t_{ABS}/t_{plant})$ =	0.173	fraction
Total effective operating time for the scrubber (t_{op}) =	CF_{total} x 8760 =	1,513	hours
SO_2 Removal Efficiency (EF) =	$(SO_{2in} - SO_{2out})/SO_{2in}$ =	80	percent
SO_2 removed per hour =	SO_{2in} x EF x Q_B =	70	lb/hour
Total SO_2 removed per year =	(SO_{2in} x EF x Q_B x t_{op})/2000 =	52.96	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
Inlet SO_2 Emissions (SO_{2in}) =	Value entered by user	0.50	lb/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05	
Atmospheric pressure at 1440 feet above sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.0	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0527

Waste Generation and Lime, Water and Power Consumption Rates:

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	[(0.000547 x S^2) + (0.00649 x S) + 1.3] x CoalF x HRF x (1/100) x A x 1,000 =	240	kW
Water Usage: Water consumption (q_{water}) =	[((0.04898 x S^2) + (0.5925 x S) + 55.11) x A x CoalF x HRF]/1,000	1.0	kgallons/hour
Lime Usage: Lime consumption rate (Q_{Lime}) =	[[((06702 x S^2)+(13.42 x S)) x A x HRF]/2,000] x (EF/0.95) =	0.05	tons/hour
Waste Generation: Waste generation rate (q_{waste}) =	[[((0.8016 x S^2) + (31.1917 x S)) x A x HRF]/2,000] x EF/0.95 =	0.1	lb/hour

SDA Cost Estimate

Total Capital Investment (TCI)

$$TCI = 1.3 \times (ABS_{cost} + BMF_{cost} + BOP_{cost})$$

Capital costs for the absorber (ABS_{cost}) =	$5,259,580	
Reagent Preparation & Waste Recycling/handling (BMF_{cost}) =	$1,692,707	
Balance of Plant Costs (BOP_{cost}) =	$6,455,553	
Total Capital Investment (TCI) =	$17,430,191	in 2020 dollars

SDA Capital Costs ($_{cost}$)

For Coal-Fired Utility Boilers >600 MW:

$$ABS_{cost} = A \times 98{,}000 \times ELEVF$$

For Coal-Fired Utility Boilers 50 and 600 MW :

$$ABS_{cost} = 637{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.6} \times (S/4)^{0.01} \times ELEVF \times RF$$

SDA Capital Costs (ABS_{cost}) =	$5,259,580	in 2020 dollars

Reagent Preparation and Waste Recycling/Handling Costs (BMF_{cost})

For Coal-Fired Utility Boilers >600 MW:

$$BMF_{cost} = A \times 52{,}000$$

For Coal-Fired Utility Boilers 50 and 600 MW :

$$BMF_{cost} = 338{,}000 \times A^{0.716} \times (S \times HRF)^{0.2} \times RF$$

Reagent Preparation & Waste Recycling/Handling (BMF_{cost}) =	$1,692,707	in 2020 dollars

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers >600 MW:

$$BOP_{cost} = 138{,}000 \times A \times ELEVF$$

For Coal-Fired Utility Boilers betwee 50 and 600 MW :

$$BOP_{cost} = 899{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.4} \times ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$6,455,553	in 2020 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$420,672
Indirect Annual Costs (IDAC) =	$925,452
Total annual costs (TAC) = DAC + IDAC	$1,346,125 in 2020 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Operator Cost) +(Annual Reagent Cost) + (Annual Make-up Water Cost) + (Annual Waste Disposal Cost) + (Annual Auxiliary Power Cost)

Annual Maintenance Cost =	0.015 x TCI =	$261,453
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	$124,800
Annual Reagent Cost =	Q_{lime} x $Cost_{reag}$ x t_{op} =	$9,584
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$13,081
Annual Make-up Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$6,471
Annual Waste Disposal Cost =	q_{waste} x $Cost_{fuel}$ x t_{op} =	$5,283
Direct Annual Cost =		$420,672 in 2020 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Annual Operator Cost + 0.4(Annual Maintenance Cost)) =	$6,881
Capital Recovery Costs (CR)=	CRF x TCI =	$918,571
Indirect Annual Cost (IDAC) =	AC + CR =	$925,452 in 2020 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ SO_2 Removed/year

Total Annual Cost (TAC) =	$1,346,125 per year in 2020 dollars
SO_2 Removed =	53 tons/year
Cost Effectiveness =	$25,420 per ton of SO_2 removed in 2020 dollars

Data Inputs (MPCA FFA Costs, Virginia Department of Public Utilities, Boiler 7, Wet Scrubber, 2022-02-14)

Enter the following data for your combustion unit:

Is the FGD for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor. Enter 1 for projects of average difficulty. Enter values >1 for more difficult retrofits and enter <1 for less difficult retrofits. 1

Directions: Enter data in highlighted data fields.

What is the gross MW rating at full load capacity (A)? 8.24 MW

Provide the following information for the coal burned:

Select type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) percent by weight **OR** SO_2 Emissions (SO_{2in}) 0.50 lb/MMBtu

Oulet SO_2 Emissions (SO_{2out}) 0.05 lb/MMBtu

What is the higher heating value of the fuel (HHV)? Btu/lb

*HHV is the weighted average value calculated using the values entered in the coal blend composition table.

*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in lb/MMBtu above

What is the estimated actual annual MWh output? 12,466 MWh

Waste from a WFDG system disposed in an onsite or offsite landfill? Offsite Landfill

Gross heat input rate (GHR) 21.24 MMBtu/MWh

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t_{ABS})	4380	Hours	Plant Elevation	1440 Feet above sea level
Number of hours the boiler operates (t_{plant})	4380	Hours		

Number of Full Time Operators (FT):

SDA System	1	
WFGD system	1.5	

Estimated equipment life:

SDA System	30	Years
Wet FGD System	30	Years
Estimated equipment life for mercury monitor for wastewater treatment system for Wet FGD Systems	6	Years

Enter the cost data for the proposed FGD System:

Desired dollar-year for Capital Costs	2020			
CEPCI for 2020	592.1	Enter the CEPCI value for 2020	541.7	2016 CEPCI*
Annual Interest Rate (i)	3.25	Percent**	** 3.25 percent is the default bank prime rate. User should enter current bank prime rate (available at	

Sorbent Cost:

Lime (for SDA)	125.00	\$/ton of Lime
Limestone (for Wet FGD)	30.00	\$/ton of Limestone
Water ($Cost_{water}$)	0.0042	\$/gallon
Electricity ($Cost_{elect}$)	0.0361	\$/kWh*
Waste Disposal cost ($Cost_{waste}$)	30.00	\$/ton
Labor Rate	60.00	\$/hour
Purchase Equipment Cost for Mercury Monitor for wastewater treatment System (MMCost)	100,000	\$/monitor

*Note: CEPCI = Chemical Engineering Plant Cost Index. The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used
Lime ($/ton)	125	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Limestone ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Water Cost ($/gallon)	0.00420	Average water rates for industrial facilities (compiled by Black & Veatch. See '50 Largest Cities Water/Wastewater Rate Survey - 2018-2019.'Available at www.bv.com/sites/default/files/2019-10/50_Largest_Cities_Rate_Survey_2018_2019_Report.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf	
Waste Disposal Cost ($/ton)	30	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Higher Heating Value (HHV) (Btu/lb)	8,826	Average HHV based 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Average Sulfur Content (%)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate March 2, 2021 (available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/).	
Hourly Labor Rate ($/hour)	60	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. January 2017. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

Wet FGD Design Parameters

The following design parameters for the wet FGD system were calculated based on the values entered on the *FGD Data Inputs* tab. These values were used to prepare the costs shown on the *Wet FGD*

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	A x GHR =	175	MMBtu/hour	
Maximum Annual MWh Output (B_{MW}) =	A x 8760 =	72,182	MWh	
Estimated Actual Annual MWh Output (B_{output}) =	Value entered by user	12,466	MWh	
Heat Rate Factor (HRF) =	Gross Plant Heat Rate/10 =	2.12		
Total System Capacity Factor (CF_{total}) =	$(B_{output}/B_{mw})*(t_{ABS}/t_{plant})$ =	0.173	fraction	
Total effective operating time for the scrubber (t_{op}) =	CF_{total} x 8760 =	1,513	hours	
SO_2 Removal Efficiency (EF) =	$(SO_{2in} - SO_{2out})/SO_{2in}$ =	90	percent	
SO_2 removed per hour =	SO_{2in} x EF x Q_B =	79	lb/hour	
Total SO_2 removed per year =	$(SO_{2in}$ x EF x Q_B x $t_{op})/2000$ =	59.57	tons/year	66.1939315
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
Inlet SO_2 Emissions (SO_{2in}) =	Value entered by user	0.50	lb/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05		
Atmospheric pressure at 1440 feet above sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.0	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Capital Recovery Factor:

Parameter	Equation	Calculated Value	
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0527	Wet FGD System
		0.1861	Mercury Monitor for Wastewater Treatment System

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$0.0112e^{0.155xS}$ x CoalF x HRF x A x 1,000 =	222	kW
Water Usage: Water consumption (q_{water}) =	[(1.674 x S + 74.68) x A x CoalF x HRF]/1,000	1.4	kgallons/hour
Limestone Usage: Limestone consumption rate ($Q_{Limestone}$) =	[17.52 x A x S x HRF]/2,000] x (EF/0.98) =	0.07	tons/hour
Waste Generation: Waste generation rate (q_{waste}) =	[1.811 x $Q_{Limestone}$ x (EF/0.98) =	0.1	tons/hour
Wastewater Flow Rate: Wastewater flow rate (F) =	A x (0.4 gallons/min/MW) =	3	gallons/minute

Wet FGD Cost Estimate

Total Capital Investment (TCI)

$$TCI = 1.3 \times (ABS_{cost} + RPE_{cost} + WHE_{Cost} + BOP_{cost}) + WWT_{Cost}$$

Capital costs for the absorber (ABS_{cost}) =	$4,788,662
Reagent Preparation Equipment Costs (RPE_{cost}) =	$1,017,721
Waste Handling Equipment (WHE_{Cost}) =	$538,892
Balance of Plant Costs (BOP_{cost}) =	$7,683,472
Wastewater Treatment Facility Costs (WWT_{cost}) =	$11,344,737
Total Capital Investment (TCI) =	$32,985,530 in 2020 dollars with disposal at offsite landfill

Wet FGD Capital Costs (ABS_{cost})

$$ABS_{cost} = 584{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.6} \times (S/2)^{0.02} \times ELEVF \times RF$$

Wet FGD Capital Costs (ABS_{cost}) =	$4,788,662 in 2020 dollars

Reagent Preparation Costs (RPE_{cost})

$$RPE_{cost} = 202{,}000 \times A^{0.716} \times (S \times HRF)^{0.3} \times RF$$

Reagent Preparation (RPE_{cost}) =	$1,017,721 in 2020 dollars

Waste Handling Equipment (WHE_{Cost})

$$WHE_{cost} = 106{,}000 \times A^{0.716} \times (S \times HRF)^{0.45} \times RF$$

Waste Recycling/Handling (WHE_{cost}) =	$538,892 in 2020 dollars

Balance of Plant Costs (BOP_{cost})

$$BOP_{cost} = 1{,}070{,}000 \times (A)^{0.716} \times (CoalF \times HRF)^{0.4} \times ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$7,683,472 in 2020 dollars

Wastewater Treatment Facility Costs (WWT_{cost})	
Wastewater Treatment Facility Costs with Onsite Landfill	
	WWT_{cost} = (41.36 F + 11,157,588) x RF x 0.898
Wastewater Treatement Facility Costs with Offsite Landfill	
	WWT_{cost} = (41.16 F + 11,557,843) x RF x 0.898
Wastewater Treatment Facility Costs (WWT_{cost}) =	$11,344,737 in 2020 dollars with disposal at offsite landfill

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$808,174	
Indirect Annual Costs (IDAC) =	$1,749,891	
Total annual costs (TAC) = DAC + IDAC	$2,558,065	in 2020 dollars

Direct Annual Costs (DAC)

DAC = Annual Maintenance Cost + Annual Operator Cost + Annual Reagent Cost + Annual Make-up Water Cost + Annual Waste Disposal Cost + Annual Auxiliary Power Cost + Annual Wastewater

Annual Maintenance Cost =	0.015 x TCI =	$494,783	
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	$187,200	
Annual Reagent Cost =	$Q_{limestone}$ x $Cost_{Limestone}$ x t_{op} =	$3,195	
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$12,146	
Annual Make-up Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$8,818	
Annual Waste Disposal Cost =	q_{waste} x $Cost_{fuel}$ x t_{op} =	$5,314	
Annual Wastewater Treatment Cost =	(6.3225F + 472,080) x 0.958 x CFtotal x ESC =	$78,107	(with disposal at offsite landfill)
Replacement Cost for Mercury Monitor =	CF_{mm} x MM_{Cost} =	$18,610	(replaced once every 6 years.)
Direct Annual Cost =		$808,174	in 2020 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Annual Operator Cost + 0.4(Annual Maintenance Cost)) =	$11,553	
Capital Recovery Costs (CR)=	CRF x TCI =	$1,738,337	
Indirect Annual Cost (IDAC) =	AC + CR =	$1,749,891	in 2020 dollars

Cost Effectiveness = Total Annual Cost/ SO_2 Removed/year

Total Annual Cost (TAC) =	$2,558,065	per year in 2020 dollars
SO_2 Removed =	60	tons/year
Cost Effectiveness =	$42,939	per ton of SO_2 removed in 2020 dollars

Data Inputs (MPCA FFA Costs, Virginia Department of Public Utilities, Boiler 11, SCR, 2022-05-05)

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 230 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 4,513 Btu/lb

What is the estimated actual annual fuel consumption? 263,816,000 lbs/Year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1440 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 0.02 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	311 days
Number of days the boiler operates (t_{plant})	311 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.15 lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.03 lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	25 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5 Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.5 Percent		
Reagent ($Cost_{reag}$)	0.554 $/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0844 $/kWh		
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00 $/hour (including benefits)*		
Operator Hours/Day	4.00 hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	($0.554/gallon of 29% Ammonia) U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated. (510 $/ton NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb SOL / ft3 SOL) / (7.48052 gal SOL / ft3 SOL) = $0.554/gallon of 29%
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	(0.0844 $/kWh) U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	(3.5%) Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	230	MMBtu/hour	Natural Gas	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	446,404,041	lbs/Year	1,944,787,645	scf/Year
Actual Annual fuel consumption (Mactual) =		263,816,000	lbs/Year	173,200,000	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00			
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.680	fraction	0.089	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5957	hours		
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	78.0	percent		
NOx removed per hour =	NOx_{in} x EF x Q_B =	27.09	lb/hour		
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	80.69	tons/year	103.4457462	
NO_x removal factor (NRF) =	EF/80 =	0.98			
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	113,564	acfm		
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	135.60	/hour		
Residence Time	$1/V_{space}$	0.01	hour		
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07			
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.05			
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.0	psia		
Retrofit Factor (RF)	Retrofit to existing boiler	1.00			

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3219	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	837.49	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	118	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	136	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	11.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	11	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	36	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,700	gallons (storage needed to store a 14 day reagent supply rounded to the nearest 1

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0607

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	132.60	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$6,937,059	in 2019 dollars
Reagent Preparation Cost (RPC) =	$1,443,027	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$2,398,314	in 2019 dollars
Total Capital Investment (TCI) =	$14,011,921	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$6,937,059 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$1,443,027 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,398,314 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$173,123 in 2019 dollars
Indirect Annual Costs (IDAC) =	$853,604 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,026,726 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$70,060 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$15,994 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$66,670 in 2019 dollars
Annual Catalyst Replacement Cost =		$20,399 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR)$ x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x $(CC_{replace})$ x 35.3	
Direct Annual Cost =		$173,123 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,080 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$850,524 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$853,604 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,026,726 per year in 2019 dollars
NOx Removed =	81 tons/year
Cost Effectiveness =	$12,724 per ton of NOx removed in 2019 dollars