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

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?
Is the SNCR for a new boiler or retrofit of an existing boiler?		
Please enter a retrofit factor equal to or greater than 0.84 based on th difficulty. Enter 1 for projects of average retrofit difficulty.	e level of 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:		
		Provide the following information for coal-fired boilers:
What is the maximum heat input rate (QB)?	137 MMBtu/hour	Type of coal burned: Sub-Bituminous
What is the higher heating value (HHV) of the fuel?	9,400 Btu/lb	Enter the sulfur content (%S) = 0.38 percent by weight
		or Select the appropriate SO ₂ emission rate:
What is the estimated actual annual fuel consumption?	74,154,894 lbs/Year	
		Ash content (%Ash): 4.12 percent by weight
Is the boiler a fluid-bed boiler?	No 🔻	
		For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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.
If the NPHR is not known, use the default NPHR value:	Fuel Type Default NPHR Coal 10 MMBtu/MW	Fraction in Coal Blend Fuel Cost %Ash Bituminous 0 Sub-Bituminous 0 Output 5.84 8.826 1.89
	Fuel Oil 11 MMBtu/MW Natural Gas 8.2 MMBtu/MW	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
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	Densities of typical S	NCR reagents:
Number of days reagent is stored (t _{storage})	14	days	50% urea so	olution 7
Estimated equipment life	20	Years	29.4% aqueo	bus NH ₃ 5
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	CEPCI = Chemical Engineerir
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*	

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) = Administrative Charges Factor (ACF) =

0.015
0.03

'1 lbs/ft³ 66 lbs/ft³

ing Plant Cost Index

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	and the ref
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/ga U.S. Geolog https://pub
			\$/gallon pr (510 \$/ton SOL / ft3 S(
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:	(0.0844 \$/k U.S. Energy
		https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	for MN ind https://ww pmt 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 \$/MN U.S. Energy Table 7.4. F https://ww
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/Ib)	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 listed unde https://ww

your own site-specific values, please enter the value used ference source ...

llon of 29% Ammonia)

gical Survey, Minerals Commodity Summaries, 2021

os.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. ice was back calculated.

NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb OL) / (7.48052 gal SOL / ft3 SOL) = \$0.554/gallon of 29%

(Wh)

Information Administration. Electric Power, January 2022 ustrial users. Available at: w.eia.gov/electricity/monthly/epm_table_grapher.php?t=e

/IBtu)

v Information Administration. Electric Power Annual 2020. Published March 2022. Available at: vw.eia.gov/electricity/annual/pdf/epa.pdf.

e rate is as of March 2, 2021 and is available as the rates r 'bank prime loan' at w.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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOX} \times SR) =$	18	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
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	2 800	gallons (storage needed to store a 14 day reagent supply
	Density =	2,800	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Equation	Calculated Value	Units
(0.47 x NOx _{in} x NSR x Q _B)/NPHR =	2.2	kW/hour
$(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$	14	gallons/hour
$H_{V} \times m_{1} \times ((1/C_{12})-1) =$	0.14	MMBtu/hour
	0.14	initia cu i
(Δfuel x %Ash x 1x10 ⁶)/HHV =	0.6	lb/hour
	Equation (0.47 x NOx _{in} x NSR x Q _B)/NPHR = (m_{sol} /Density of water) x ((C_{stored} / C_{inj}) - 1) = Hv x $m_{reagent}$ x ((1/ C_{inj})-1) = (Δ fuel x %Ash x 1x10 ⁶)/HHV =	EquationCalculated Value $(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR =$ 2.2 $(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$ 14Hv x m_{reagent} \times ((1/C_{inj})-1) =0.14 $(\Delta fuel \times \%Ash \times 1x10^6)/HHV =$ 0.6

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:	
	$TCI = 1.3 x (SNCR_{cost} + BOP_{cost})$
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

 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} = 2	220,000 x (B _{MW} x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF	
For Fuel Oil and Natural Gas-Fired Utility Boilers	5:	
SNC	$R_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$	
For Coal-Fired Industrial Boilers:		
SNCR _{cost} = 22	$0,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$	
For Fuel Oil and Natural Gas-Fired Industrial Boi	ilers:	
SNCR _{cos}	_{st} = 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x RF	
SNCR Capital Costs (SNCR _{cost}) =	\$1,201,809 in 2019 dollars	
For Coal Fired Utility Boilors	Air Pre-Heater Costs (APH _{cost})*	
	$-60.000 \times (B_{10} \times HBE \times CoolE)^{0.78} \times AHE \times BE$	
APH _{co}	$_{\text{ost}} = 69,000 \text{ x} (B_{\text{MW}} \text{ x HKF x COAIF}) \text{ x AHF x KF}$	
For Coal-Fired industrial Bollers.	-60,000,000,000,000,000,000,000,000,000,	
APH _{cost}	= 69,000 x (0.1 x Q_B x HRF x COaIF) x AHF x RF	
Air Bre-Heater Costs (APH) -	\$0 in 2019 dollars	
* Not applicable - This factor applies only to coal-fired bo	ilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of	
sulfur dioxide.	inclusion bitalininous cour and clinic equal to or greater than sis/window or	
	Balance of Plant Costs (BOP _{cost})	
For Coal-Fired Utility Boilers:	0.12	
BOP _{cost} = 32	20,000 x $(B_{MW})^{0.33}$ x $(NO_x Removed/hr)^{0.12}$ x BTF x RF	
For Fuel Oil and Natural Gas-Fired Utility Boilers	S:	
BOP _{cost} =	= 213,000 x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x RF	
For Coal-Fired Industrial Boilers:		
BOP _{cost} = 320),000 x (0.1 x Q _B) ^{0.33} x (NO _x Removed/hr) ^{0.12} x BTF x RF	
For Fuel Oil and Natural Gas-Fired Industrial Boi	ilers:	
BOP _{cost} = 2	13,000 x (Q _B /NPHR) ^{0.33} x (NO _x Removed/hr) ^{0.12} x 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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$22,797 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$958 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$293 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$1,376 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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 projects of average retrofit difficulty.	level of difficu	lty. Enter 1 for	1.5	* NOTE: You must document why a retrofit factor of 1.5 is appropriate the proposed project.	for
Complete all of the highlighted data fields:					
What is the maximum heat input rate (QB)?			137 MMBtu/hour	Provide the following information for coal-fired boil Type of coal burned: Sub-Bituminous	ers:
What is the higher heating value (HHV) of the fuel?		9	,400 Btu/lb	Enter the sulfur content (%S) = 0	.38 p
What is the estimated actual annual fuel consumption?		74,154	<mark>,894</mark> lbs/Year		
				For units burning coal blends: Note: The table below is pre-populated wit these parameters in the table below. If the default values provided.	h def actu
Enter the net plant heat input rate (NPHR)			10 MMBtu/MW	Fraction i	n
If the NPHR is not known, use the default NPHR value:		Fuel Type Coal Fuel Oil Natural Gas	Default NPHR 10 MMBtu/MW 11 MMBtu/MW 8.2 MMBtu/MW	Coal Type Coal Blen Bituminous Sub-Bituminous Lignite Image: Coal Blen	0 0 0
			·	Please click the calculate button to calculate values based on the data in the table above	e we
Plant Elevation			840 Feet above sea level	For coal-fired boilers, you may use either Meth catalyst replacement cost. The equations for b and 86 on the Cost Estimate tab. Please select	od 1 oth i you



Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	265 days	Number of SCR reactor chambers (n _{scr})		
Number of days the boiler operates (t _{plant})	265 days	Number of catalyst layers (R _{layer})	3	3
Inlet NO _x Emissions (NOx _{in}) to SCR	0.33 lb/MMBtu	Number of empty catalyst layers (R _{empty})	:	
Outlet NO _x Emissions (NOx _{out}) from SCR	0.07 Ib/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)	UNI	Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	400	[°] F
* For industrial boilers, the typical equipment life is between 20 and 25 years.			73:	ft ³ /min-MMBtu/hour
		Base case fuel gas volumetric flow rate fact	ctor (Q _{fuel})	
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default		
Density of reagent as stored (ρ_{stored})	56 Ib/cubic feet*	values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.		
Number of days reagent is stored (t _{storage})	14 days	Densi	sities of typical SCR reagents:	
		50% u	urea solution	71 lbs/ft ³
		29.49	% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Select the reagent used

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a default
Catalyst cost (CC _{replace})	227.00	catalyst and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a de

▼

Ammonia

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

efault value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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
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.

115.01424

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate) ^Y -1), where $Y = H_{catalyts}/(t_{SCR} x 24 \text{ hours})$ 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	(A) ^{0.5}	11.0	feet
reactor =	(Ascr)	11.0	leet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	64	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent

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 1

Capital Recovery Factor:

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

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

14 day reagent supply rounded to t

Density =

t (MW) = 17.03 g/mole 56 lb/ft³

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:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (B_{MW} \text{ x} HRF \text{ x} CoalF)^{0.92} \text{ x} ELEVF \text{ x} RF$	
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
	Persont Properation Casts (PPC)	
For Coal-Fired Litility Boilers >25 MW:		
	RPC = 564,000 x (NOx _{in} x B _{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:	A 35	
	$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$	
Reagant Propagation Costs (PPC) -		\$2,217,828 in 2010 dollars
Reagent Preparation Costs (RPC) –		\$2,517,828 III 2019 Uoliais
	Air Pre-Heater Costs (APHC)*	
For Coal-Fired Utility Boilers >25MW:		
	APHC = 69,000 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH _{cost}) =		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers that	t 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 x $(B_{MW} x HRFx CoalF)^{0.42} x ELEVF x RF$

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

BPC = 529,000 x $(0.1 \times Q_B \times CoalF)^{0.42}$ ELEVF x 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): $n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
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 (N	IPCA FFA Costs, American Cr	ystal 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?	ndustrial 💌	What type of fuel does the unit burn?
Is the SNCR for a new boiler or retrofit of an existing boiler?		
Please enter a retrofit factor equal to or greater than 0.84 based on th difficulty. Enter 1 for projects of average retrofit difficulty.	e level of 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	Provide the following information for coal-fired boilers: Type of coal burned: Sub-Bituminous
What is the higher heating value (HHV) of the fuel?	<mark>9,400</mark> Btu/lb	Enter the sulfur content (%S) = 0.38 percent by weight
What is the estimated actual annual fuel consumption?	89,310,638 lbs/Year	Select the appropriate SO ₂ emission rate: Ash content (%Ash): 4.12 percent by weight
Is the boiler a fluid-bed boiler?	No	
		For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW	Fraction in Coal BlendFraction in %SFuel Cost %AshBituminous01.849.2311,8412.4Sub-Bituminous00.415.848,8261.89Lignite00.8213.66,6261.74
		Please click the calculate button to calculate weighted values based on the data in the table above.

μı	oviueu.	
on	Table	

	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
1	9.23	11,841	2.4
L	5.84	8,826	1.89
2	13.6	6,626	1.74

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	265	days	Plant Elevation	840 Feet above
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			
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	Densities of typical SI	NCR reagents:
Number of days reagent is stored (t _{storage})	14	days	50% urea sc	lution 7
Estimated equipment life	20	Years	29.4% aqueo	us NH ₃ 5
Select the reagent used	Ammonia			

Enter the cost data for the proposed SNCR:

	2010	
Desired dollar-year	2019	
CEPCI for 2019	607.5 Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering
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*	

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) = Administrative Charges Factor (ACF) =

0.015
0.03

71 lbs/ft³ 56 lbs/ft³

ing Plant Cost Index

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	and the ref
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/ga U.S. Geolog https://pub
			\$/gallon pr (510 \$/ton SOL / ft3 S(
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:	(0.0844 \$/k U.S. Energy
		https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	for MN ind https://ww pmt 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 \$/MN U.S. Energy Table 7.4. F https://ww
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/Ib)	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 listed unde https://ww

your own site-specific values, please enter the value used ference source ...

llon of 29% Ammonia)

gical Survey, Minerals Commodity Summaries, 2021

os.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. ice was back calculated.

NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb OL) / (7.48052 gal SOL / ft3 SOL) = \$0.554/gallon of 29%

(Wh)

Information Administration. Electric Power, January 2022 ustrial users. Available at: w.eia.gov/electricity/monthly/epm_table_grapher.php?t=e

ı /IBtu)

Published March 2022. Available at: ww.eia.gov/electricity/annual/pdf/epa.pdf.

e rate is as of March 2, 2021 and is available as the rates r 'bank prime loan' at w.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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$	21	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
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	2 200	gallons (storage needed to store a 14 day reagent supply
	Density =	3,200	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$(0.47 \times NOX_{in} \times NSR \times Q_B)/NPHR =$	2.6	kw/nour
Water Usage:			
Water consumption (q _w) =	$(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$	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	$(\Delta fuel x % \Delta sb x 1x10^{6})/HH)/ -$	0.7	lb/hour
consumption (Δash) =		0.7	

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:					
	$TCI = 1.3 x (SNCR_{cost} + APH_{cost} + BOP_{cost})$				
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 bo	ilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu				
of sulful dioxide.					
	SNCR Capital Costs (SNCR _{cost})				
For Coal-Fired Utility Boilers:	0.42				
SNCR _{cost} = 2	220,000 x (B _{MW} x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF				
For Fuel Oil and Natural Gas-Fired Utility Boilers	S:				
SNC	$R_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$				
For Coal-Fired Industrial Boilers:	0.42				
SNCR _{cost} = 22	$(0,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$				
For Fuel Oil and Natural Gas-Fired Industrial Boi	ilers:				
SNCR _{cos}	$_{st}$ = 147,000 x ((Q _B /NPHR)x HRF) ⁶⁴² x ELEVF x RF				
	¢1 200 420 in 2010 dollars				
SNCR Capital Costs (SNCR _{cost}) =	\$1,299,439 In 2019 dollars				
	Air Pre-Heater Costs (APH _{cost})*				
For Coal-Fired Utility Boilers:					
APH _{co}	_{ost} = 69,000 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF				
For Coal-Fired Industrial Boilers:					
APH _{cost}	= 69,000 x (0.1 x Q _B x HRF x CoalF) ^{0.78} x AHF x RF				
Air Pre-Heater Costs (APH _{cost}) =	\$0 in 2019 dollars				
* Not applicable - This factor applies only to coal-fired bo	ilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of				
sultur dioxide.					
	Balance of Plant Costs (BOP _{cost})				
For Coal-Fired Utility Boilers:					
BOP _{cost} = 320,000 x $(B_{MW})^{0.33}$ x $(NO_{R}emoved/hr)^{0.12}$ x BTF x RF					
For Fuel Oil and Natural Gas-Fired Utility Boilers:					
$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_{x}Removed/hr)^{0.12} \times RF$					
For Coal-Fired Industrial Boilers:					
$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$					
For Fuel Oil and Natural Gas-Fired Industrial Boi	lers:				
BOP _{cost} = 2	13,000 x (Q _B /NPHR) ^{0.33} x (NO _x Removed/hr) ^{0.12} x 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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$26,624 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$1,119 in 2019 dollars
Annual Water Cost =	$q_{water} x Cost_{water} x t_{op} =$	\$342 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$1,607 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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 (N	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?	ial 👻	What type of fuel does the unit burn?
Please enter a retrofit factor between 0.8 and 1.5 based on the level of diff projects of average retrofit difficulty.	iculty. Enter 1 for 1.5 * NC the	DTE: You must document why a retrofit factor of 1.5 is appropriate for proposed project.
Complete all of the highlighted data fields:		
What is the maximum heat input rate (QB)?	165 MMBtu/hour	Provide the following information for coal-fired boilers: Type of coal burned: Sub-Bituminous
What is the higher heating value (HHV) of the fuel?	9,400 Btu/Ib	Enter the sulfur content (%S) = 0.38 percent by weight
What is the estimated actual annual fuel consumption?	89,310,638 lbs/Year	For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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.
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW	Coal TypeCoal Blend%SHHV (Btu/lb)Bituminous01.8411,841Sub-Bituminous00.418,826Lignite00.826,685
Plant Elevation	840 Feet above sea level	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 • O Method 2 • O Method 3 • O Method 3 • O Method 4 • O Method 4

- O Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	265 days	Number of SCR reactor chambers (n _{scr})	1	
Number of days the boiler operates (t _{plant})	265 days	Number of catalyst layers (R _{layer})	3	
Inlet NO _x Emissions (NOx _{in}) to SCR	0.32 lb/MMBtu	Number of empty catalyst layers (R _{empty})	1	
Outlet NO _x Emissions (NOx _{out}) from SCR	0.06 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2	opm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK	Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		Flue gas flow rate (Q _{fluegas})		
		(Enter "UNK" if value is not known)	103000 a	acfm
Estimated operating life of the catalyst (H _{catalyst})	24,000 hours			
Estimated SCR equipment life	20 Years*	Gas temperature at the SCR inlet (T)	460 °	Ϋ́F
* For industrial boilers, the typical equipment life is between 20 and 25 years.			(C) 624 t	ft ³ /min-MMBtu/hour
		Base case fuel gas volumetric flow rate factor	r (Q _{fuel})	
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default		
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*	values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.		
Number of days reagent is stored (t _{storage})	14 days	Densitie	es of typical SCR reagents:	
		50% ure	ea solution	71 lbs/ft ³
		29.4% a	aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Select the reagent used

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemica
Annual Interest Rate (i)	3.5	Percent	_
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	
Electricity (Cost _{elect})	0.0844	0.0844 \$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a defaul
Catalyst cost (CC _{replace})	227.00	catalyst and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a de

▼

Ammonia

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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 =	$NOx_{in} \times EF \times Q_B =$	42.90	lb/hour
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	109.14	tons/year
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 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.

134.3232

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	(A) ^{0.5}	11 1	foot
reactor =	(A _{SCR})	11.1	leet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	62	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m _{reagent}) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx} =$	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

Capital Recovery Factor:

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

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

Density =

(MW) = 17.03 g/mole 56 lb/ft³

a 14 day reagent supply rounded to

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:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (0.1 \text{ x} Q_B \text{ x} \text{ CoalF})^{0.92} \text{ x} \text{ ELEVF x RF}$	
CCD Consisted Coasts (CCD) -		67 424 706 in 2010 dellars
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 x (NO x_{in} x B _{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NO x_{in} x Q_B x EF) ^{0.25} x RF	
Reagant Propagation Costs (PDC) -		\$2,429,121 in 2010 dollars
Reagent Preparation Costs (RPC) –		\$2,428,131 III 2019 UUIIdi S
	Air Pre-Heater Costs (APHC)*	
For Coal-Fired Utility Boilers >25MW:		
	APHC = 69,000 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x RF	
		ćo iz 2010 delleze
All Pre-Healer Costs (APH _{cost}) =	thurn bituminous coal and amit agual to an greater than 21b/MMPtu of sulfur diavida	\$0 IN 2019 dollars
Not applicable - This factor applies only to coal-fifed bollers the		
	Balance of Plant Costs (BPC)	
For Coal-Fired Utility Boilers >25MW:		

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

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

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

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): $n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		* 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?	
Is the SNCR for a new boiler or retrofit of an existing boiler?	t 💌		
Please enter a retrofit factor equal to or greater than 0.84 based on th difficulty. Enter 1 for projects of average retrofit difficulty.	ne level of 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:			
		Provide the following information for coal-fired boilers:	
What is the maximum heat input rate (QB)?	356 MMBtu/hour	Type of coal burned:	
What is the higher heating value (HHV) of the fuel?	9,400 Btu/lb	Enter the sulfur content (%S) = 0.38 percent by weight	
		or Select the appropriate SO ₂ emission rate: Not Applicable	
What is the estimated actual annual fuel consumption?	210,661,000 lbs/Year		
		Ash content (%Ash): 4.12 percent by weight	
Is the boiler a fluid-bed boiler?	No		
		For units burning coal blends:	
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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.	
If the NPHR is not known, use the default NPHR value:	Fuel Type Default NPHR	Fraction in Coal Blend S %Ash HHV (Btu/lb) (\$/MMBtu) Bituminous 0 1.84 9.23 11.841 2.4	
	Coal 10 MMBtu/MW	Sub-Bituminous 0 0.41 5.84 8,826 1.89	
	Fuel Oil 11 MMBtu/MW	Lignite 0 0.82 13.6 6,626 1.74	
	Natural Gas 8.2 MMBtu/MW		
		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 $(t_{s_{NCR}})$	265	days	Plant Elevation	840 Feet above
Number of days the boiler operates (t _{plant})	265	days		
Inlet NO _x Emissions (NOx _{in}) to SNCR	0.34	b/MMBtu		
Oulet NO _x Emissions (NOx _{out}) from SNCR	0.306	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	Densities of typical SI	NCR reagents:
Number of days reagent is stored (t _{storage})	14	days	50% urea sc	lution 7
Estimated equipment life	20	Years	29.4% aquec	us NH ₃ 5
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	CEPCI = Chemical Engineerir
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*	

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) = Administrative Charges Factor (ACF) =

0.015
0.03

71 lbs/ft³ 56 lbs/ft³

ing Plant Cost Index

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	and the ref
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/ga U.S. Geolog https://pub
			\$/gallon pr (510 \$/ton SOL / ft3 S(
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:	(0.0844 \$/k U.S. Energy
		https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	for MN ind https://ww pmt 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 \$/MN U.S. Energy Table 7.4. F https://ww
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/Ib)	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 listed unde https://ww

your own site-specific values, please enter the value used ference source ...

llon of 29% Ammonia)

gical Survey, Minerals Commodity Summaries, 2021

os.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. ice was back calculated.

NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb OL) / (7.48052 gal SOL / ft3 SOL) = \$0.554/gallon of 29%

(Wh)

Information Administration. Electric Power, January 2022 ustrial users. Available at: w.eia.gov/electricity/monthly/epm_table_grapher.php?t=e

/IBtu)

v Information Administration. Electric Power Annual 2020. Published March 2022. Available at: vw.eia.gov/electricity/annual/pdf/epa.pdf.

e rate is as of March 2, 2021 and is available as the rates r 'bank prime loan' at w.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		1
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	1
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		1
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		1

* 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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$	47	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
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	7.400	gallons (storage needed to store a 14 day reagent supply
	Density =	7,400	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Equation	Calculated Value	Units
(0.47 x NOx _{in} x NSR x Q _B)/NPHR =	6.0	kW/hour
$(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =$	37	gallons/hour
$Hv \times m_{reagent} \times ((1/C_{ini})-1) =$	0.38	MMBtu/hour
		,
$(\Delta fuel x %Ash x 1x10^{6})/HHV =$	1.7	lb/hour
	Equation $(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR =$ $(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$ $Hv \times m_{reagent} \times ((1/C_{inj})-1) =$ $(\Delta fuel \times \%Ash \times 1\times 10^6)/HHV =$	EquationCalculated Value $(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR =$ 6.0 $(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$ 37 $Hv \times m_{reagent} \times ((1/C_{inj})-1) =$ 0.38 $(\Delta fuel \times \%Ash \times 1x10^6)/HHV =$ 1.7

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:		
	TCI = 1.3 x (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	

 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} = 2	220,000 x $(B_{MW} \times HRF)^{0.42}$ x CoalF x BTF x ELEVF x RF	
For Fuel Oil and Natural Gas-Fired Utility Boilers	:	
SNC	R _{cost} = 147,000 x (B _{MW} x HRF) ^{0.42} x ELEVF x RF	
For Coal-Fired Industrial Boilers:		
SNCR _{cost} = 22	0,000 x (0.1 x Q _B x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF	
For Fuel Oil and Natural Gas-Fired Industrial Boi	lers:	
SNCR _{cos}	_{tt} = 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x RF	
SNCR Capital Costs (SNCR _{cost}) =	\$1,794,823 in 2019 dollars	
	Air Pre-Heater Costs (APH)*	
For Coal-Fired Utility Boilers:		
APH _{en}	$_{cs} = 69.000 \text{ x} (B_{MM} \text{ x HRF x CoalF})^{0.78} \text{ x AHF x RF}$	
For Coal-Fired Industrial Boilers:		
APHrost	= 69.000 x (0.1 x Q _B x HRF x CoalF) ^{0.78} x AHF x RF	
031	, u v v	
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} = 32	20,000 x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x BTF x RF	
For Fuel Oil and Natural Gas-Fired Utility Boilers:		
$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_{x}Removed/hr)^{0.12} \times RF$		
For Coal-Fired Industrial Boilers:		
$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$		
For Fuel Oil and Natural Gas-Fired Industrial Boilers:		
$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$		
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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$67,018 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$2,817 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$860 in 2019 dollars
Additional Fuel Cost =	Δ Fuel 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?	ıstrial		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 d projects of average retrofit difficulty.	lifficulty. Enter 1 for	1.5	* NOTE: You must document why a retrofit factor of 1.5 the proposed project.	i is appropriate for	
Complete all of the highlighted data fields:					
What is the maximum heat input rate (QB)?	356	MMBtu/hour	Type of coal burned:	minous	
What is the higher heating value (HHV) of the fuel?	9,400	Btu/lb	Enter the sulfur content (%S) =	0.38 percent by weight	
What is the estimated actual annual fuel consumption?	210,661,000	lbs/Year	For units burning coal blends:		
			Note: The table below is pre-p these parameters in the table default values provided	opulated with default values for HHV and %S. Please en below. If the actual value for any parameter is not know	nter the actual values fo vn, you may use the
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW		Fraction in Coal Blend %S HHV (Btu/lb)	
If the NPHR is not known, use the default NPHR value:	Fuel Type Coal Fuel Oil Natural Gas	Default NPHR 10 MMBtu/MW 11 MMBtu/MW 8.2 MMBtu/MW	Bituminous Sub-Bituminous Lignite	0 1.84 11,841 0 0.41 8,826 0 0.82 6,685	
Plant Elevation	840	Feet above sea level	Please click the calculate butto values based on the data in the	on to calculate weighted average e table above.	
			For coal-fired boilers, you may use catalyst replacement cost. The equ and 86 on the <i>Cost Estimate</i> tab. P	either Method 1 or Method 2 to calculate the ations for both methods are shown on rows 85 lease 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 SCR reactor chambers (n _{scr})	1	
Number of days the boiler operates (t _{plant})	265 days	Number of catalyst layers (R _{layer})	3	
Inlet NO _x Emissions (NOx _{in}) to SCR	0.34 Ib/MMBtu	Number of empty catalyst layers (R _{empty})	1	
Outlet NO _x Emissions (NOx _{out}) from SCR	0.07 Ib/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
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	450	°F
* For industrial boilers, the typical equipment life is between 20 and 25 years.			590	ft ³ /min-MMBtu/hour
		Base case fuel gas volumetric flow rate facto	ctor (Q _{fuel})	-, ,
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default		
Density of reagent as stored (ρ_{stored})	56 Ib/cubic feet*	values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.		
Number of days reagent is stored (t _{storage})	14 days	Densi	sities of typical SCR reagents:	
		50% u	urea solution	71 lbs/ft ³
		29.4%	% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Select the reagent used

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemica
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a default
Catalyst cost (CC _{replace})	227.00	catalyst and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a d

▼

Ammonia

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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 =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	268.81	tons/year
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.

338.12144

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 (Volastalyst) =			
	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	(A) ^{0.5}	15.0	foot
reactor =	(A _{SCR})	15.9	leet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	64	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent
		-

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

Capital Recovery Factor:

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

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

Density =

t (MW) = 17.03 g/mole 56 lb/ft³

14 day reagent supply rounded to t

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

* 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 x (NRF) ^{0.2} x (0.1 x Q _B x CoalF) ^{0.92} x ELEVF x RF	
SCD Capital Casts (SCD) -		\$15,012,241 in 2010 dollars
SCR Capital Costs (SCR _{cost}) –		\$15,012,541 III 2019 dollars
	Reagent Preparation Costs (RPC)	
For Coal-Fired Utility Boilers >25 MW:		
	RPC = 564,000 x (NO x_{in} x B _{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NOx _{in} x Q _B x EF) ^{0.25} x 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 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x 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 x $(B_{MW} x HRFx CoalF)^{0.42} x ELEVF x RF$

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

BPC = 529,000 x $(0.1 \times Q_B \times CoalF)^{0.42}$ ELEVF x 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 =	$m_{sol} \times Cost_{reag} \times t_{op} =$	\$53,281 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$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): $n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$ Method 2 (for coal-fired industrial boilers): $(O_{replace}/R_{replace}) \times 0.4 \times (CoalE)^{2.9} \times (NBE)^{0.71} \times (CC_{replace}) \times 35.3$		* Calculation Method 1 selected.
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	
		Based on percentage of TEC:
		12% Foundation & Supports, 40% Erection,
Total Installation Cost (TIC)/Balance of		1% Electrical Installation, 30% Piping, 1%
Plant Cost ^C	5,494,900	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

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

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.

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	
		Based on percentage of TEC:
		4% Foundation & Supports, 50% Erection,
Total Installation Cost (TIC)/Balance of		8% Electrical Installation, 1% Piping, 4%
Plant Cost ^C	4,159,800	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

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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 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

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

Total Annualized Costs (TAC)5,646,800DAC + 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	
		Based on percentage of TEC: 12%
		Foundation & Supports, 40% Erection, 1%
Total Installation Cost		Electrical Installation, 30% Piping, 1% Painting,
(TIC)/Balance of Plant Cost ^C	1,532,500	1% Insulation
Flatwork/Drainage/Retrofit ^D	52,000	Estimated HDR
Total Direct Investment (TDI)	3.387.400	TEC + TIC + Site Prep. = TDI

180,300 18,000 36,100	10% of TEC1% of TEC2% of TEC (Adjusted, HDR)
180,300 18,000	10% of TEC 1% of TEC
180,300	10% of TEC
/	
180.300	10% of TEC
90,100	5% of TEC
180,300	10% of TEC (Retrofit Adjustment, HDR)
	180,300 90,100

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

^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.

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		

Indirect Annual Costs (IAC)	576,500	
DSI Annualized Costs	334,100	(Capital Investment) x (CFR of 0.08024)
Insurance	40,700	1% of Total Capital Investment
Property Taxes	40,700	1% of Total Capital Investment
Administrative Charges	81,500	2% of Total Capital Investment
Overhead	79,500	60% of O&M Labor

^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		
		Based on percentage of TEC: 12%	
		Foundation & Supports, 40% Erection, 1%	
Total Installation Cost		Electrical Installation, 30% Piping, 1% Painting,	
(TIC)/Balance of Plant Cost ^C	1,540,700	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	
		Based on percentage of TEC:
		4% Foundation & Supports, 50% Erection,
Total Installation Cost (TIC)/Balance of		8% Electrical Installation, 1% Piping, 4%
Plant Cost ^C	10,580,600	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.

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):

Description	DSI	
Emission Rate (Ib/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

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

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

7,118,700

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	
		Based on percentage of TEC:
		12% Foundation & Supports, 40% Erection,
Total Installation Cost (TIC)/Balance of		1% Electrical Installation, 30% Piping, 1%
Plant Cost ^C	3,100,200	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.

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		
		Based on percentage of TEC: 4%	
		Foundation & Supports, 50% Erection, 8%	
Total Installation Cost (TIC)/Balance of		Electrical Installation, 1% Piping, 4% Painting,	
Plant Cost ^C	2,347,000	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			

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

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.

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	153 000	1% of Total Capital Investment

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

Indirect Annual Costs (IAC)	2,351,600	
Fabric Filter Annualized Costs ^D	569,800	(Capital Investment) x (CFR of 0.08204)
Dry FGD Annualized Costs ^D	692,600	(Capital Investment) x (CFR of 0.08204)
Insurance	153,900	1% of Total Capital Investment
Property Taxes	153,900	1% of Total Capital Investment

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

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		
		Based on percentage of TEC: 12 Foundation & Supports 40% Frection 1%	
Total Installation Cost		Electrical Installation, 30% Piping, 1% Painting.	
(TIC)/Balance of Plant Cost ^C	864,000	1% Insulation	
Flatwork/Drainage/Retrofit ^D	52,000	Estimated HDR	
Total Direct Investment (TDI)	1,932,500	TEC + TIC + Site Prep. = TDI	

CRK No. 1 Dry Sorbent Injection Capital Cost Summary

Total Indirect Investment (TII)	386,400	
Performance Test	20,300	2% of TEC (Adjusted HDR)
Start-up Assistance	10,200	1% of TEC
Contractor Fees	101,700	10% of TEC
Construction & Field Expense	101,700	10% of TEC
Engineering	50,800	5% of TEC
Contingency	101,700	10% of TEC (Retrofit Adjustment, HDR)
Indirect Capital Cost ^C		

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.

2,318,900

^D Estimated by HDR.

Total Turnkey Cost (TTC)

Description of Cost	(\$) [^]	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)	

CRK No. 1 Dry Sorbent Injection Annual Cost Summary

Total Annualized Costs (TAC)	484,800	DAC + IAC = TAC

^A Values rounded to the nearest \$100.

Indirect Annual Costs (IAC)

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

348,100

^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
166,778
324,678

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

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

461,400

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

122,300	3% of TEC
407,800	10% of TEC
407,800	10% of TEC
407,800	10% of TEC
40,800	1% of TEC
40,800	1% of TEC
1,427,300	
	122,300 407,800 407,800 407,800 40,800 40,800 1,427,300

Total Turnkey Cost (TTC)	9,427,000	TDI + TII = TTC
	5,727,000	

^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.

CRK No. 2 Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	(\$) [^]	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	
		Based on percentage of TEC: 4% Foundation & Supports, 50% Frection, 8%
Total Installation Cost (TIC)/Balance of		Electrical Installation, 1% Piping, 4% Painting,
Plant Cost ^C	2,623,700	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

106,400	3% of TEC
354,600	10% of TEC
709,100	20% of TEC
354,600	10% of TEC
35,500	1% of TEC
35,500	1% of TEC
1,595,700	
	106,400 354,600 709,100 354,600 35,500 35,500 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.

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

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

Indirect Annual Costs (IAC)	2,603,700	
Fabric Filter Annualized Costs ^D	637,000	(Capital Investment) x (CFR of 0.08204)
Dry FGD Annualized Costs ^D	773,400	(Capital Investment) x (CFR of 0.08204)
Insurance	171,900	1% of Total Capital Investment
Property Taxes	171,900	1% of Total Capital Investment
Administrative Charges	343,800	2% of Total Capital Investment
	•	

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

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

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

3,635,800

Description of Cost	(\$) [^]	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	
		Based on percentage of TEC:12%Foundation & Supports, 40% Erection, 1%
Total Installation Cost		Electrical Installation, 30% Piping, 1% Painting
(TIC)/Balance of Plant Cost ^C	966,100	1% Insulation
Flatwork/Drainage/Retrofit ^D	52,000	Estimated HDR
Total Direct Investment (TDI)	2,154,700	TEC + TIC + Site Prep. = TDI

CRK No. 2 Dry Sorbent Injection Capital Cost Summary

Total Indirect Investment (TII)	432,000	
Performance Test	22,700	2% of TEC (Adjusted HDR)
Start-up Assistance	11,400	1% of TEC
Contractor Fees	113,700	10% of TEC
Construction & Field Expense	113,700	10% of TEC
Engineering	56,800	5% of TEC
Contingency	113,700	10% of TEC (Retrofit Adjustment, HDR)
Indirect Capital Cost		

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.

2,586,700

^D Estimated by HDR.

Total Turnkey Cost (TTC)

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	

CRK No. 2 Dry Sorbent Injection Annual Cost Summary

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	
		Based on percentage of TEC: 12%
		Foundation & Supports, 40% Erection, 1%
Total Installation Cost		Electrical Installation, 30% Piping, 1% Painting,
(TIC)/Balance of Plant Cost ^C	1,884,200	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	
		Based on percentage of TEC:
		4% Foundation & Supports, 50% Erection,
Total Installation Cost (TIC)/Balance of		8% Electrical Installation, 1% Piping, 4%
Plant Cost ^C	9,927,400	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.

CRK Dry Sorbent Injection	Annual Cost Summary
----------------------------------	----------------------------

Description of Cost	(\$) [^]	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	
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):

Description	DSI
Emission Rate (Ib/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

Table 2 - CRK SO₂ Cost of Compliance

Interest Rate Comparison

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

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

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

6,648,400

Emission Reduction (tpy)	515
Cost Effectivness (\$/ton)	12,900
Data Inputs (MDCA EEA Costs Roi	co White Depart Roilor 1 SNCR 2022 OF OF)
---	---
Data inputs (MPCA FFA COSIS, DOI:	se white Paper, Boher 1, SNCR, 2022-05-05j
Enter the following data for your combustion unit:	
Is the combustion unit a utility or industrial boiler?	What type of fuel does the unit burn? Natural Gas 🔻
Is the SNCR for a new boiler or retrofit of an existing boiler?	
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.	
Complete all of the highlighted data fields:	Not applicable to units burning fuel oil or natural gas
What is the maximum heat input rate (QB)? 398.0 MMBtu/hour	Type of coal burned: Not Applicable 🗸
What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf	Enter the sulfur content (%S) = percent by weight
	Select the appropriate SO ₂ emission rate: Not Applicable
What is the estimated actual annual fuel consumption? 1,414,842,703 scf/Year	
Is the boiler a fluid-bed boiler?	Ash content (%Ash):
	Not applicable to units buring fuel oil or natural gas
Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW	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
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	Fraction in Coal Blend%S%AshHHV (Btu/lb)Fuel Cost (\$/MMBtu)Bituminous01.849.2311,8412.4Sub-Bituminous00.415.848,8261.89Lignite00.8213.66,6261.74Please 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 Plant Elevation 1129 Feet above Number of days the boiler operates (t _{plant}) 351 days Image: Constraint operates (t _{plant}) 1129 Feet above Inlet NOx Emissions (NOx _{in}) to SNCR 0.131 lb/MMBtu Image: Constraint operates (t _{plant}) Image: Constraint operates (t _{plant}) Image: Constraint operate (t _{stored}) Image: Constraint operate (t _{plant})					
Number of days the boiler operates (t _{plant}) 351 Inlet NO _x Emissions (NOx _{ini}) to SNCR 0.131 Oulet NO _x Emissions (NOx _{out}) from SNCR 0.08 Estimated Normalized Stoichiometric Ratio (NSR) 1.05 Concentration of reagent as stored (C _{stored}) 29 Density of reagent as stored (C _{stored}) 56 Concentration of reagent injected (C _{inj}) 10 Number of days reagent is stored (t _{storage}) 14 Estimated equipment life 20 Select the reagent used Ammonia	Number of days the SNCR operates (t_{SNCR})	351	days	Plant Elevation	1129 Feet above
Inlet NOx Emissions (NOxin) to SNCR 0.131 Ib/MMBtu Oulet NOx Emissions (NOxout) from SNCR 0.08 Ib/MMBtu Estimated Normalized Stoichiometric Ratio (NSR) 1.05 Concentration of reagent as stored (C _{stored}) 29 Percent Density of reagent as stored (C _{stored}) 56 Ib/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 Immonia	Number of days the boiler operates (t _{plant})	351	days		
Oulet NOx Emissions (NOxout) from SNCR 0.08 lb/MMBtu Estimated Normalized Stoichiometric Ratio (NSR) 1.05 Concentration of reagent as stored (Cstored) 29 Percent Density of reagent as stored (Pstored) 56 lb/ft ³ Concentration of reagent injected (Cinj) 10 percent Number of days reagent is stored (tstorage) 14 days Estimated equipment life 20 Years Select the reagent used Ammonia	Inlet NO _x Emissions (NOx _{in}) to SNCR	0.131	lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR) 1.05 Concentration of reagent as stored (C _{stored}) 29 Percent Density of reagent as stored (p _{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	Oulet NO _x Emissions (NOx _{out}) from SNCR	0.08	lb/MMBtu		
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	Estimated Normalized Stoichiometric Ratio (NSR)	1.05			
Density of reagent as stored (ρ _{stored})56 lb/ft³Concentration of reagent injected (C _{inj})10 percentNumber of days reagent is stored (t _{storage})14 daysEstimated equipment life20 YearsSelect the reagent usedAmmonia	Concentration of reagent as stored (C _{stored})	29	Percent]	
Concentration of reagent injected (Cinj)10 percentDensities of typical SNCR reagents: 50% urea solution7Number of days reagent is stored (t _{storage})14 days50% urea solution7Estimated equipment life20 Years29.4% aqueous NH356Select the reagent usedAmmonia10	Density of reagent as stored (ρ_{stored})	56	lb/ft ³		
Number of days reagent is stored (t _{storage}) 14 days 50% urea solution 72 Estimated equipment life 20 Years 29.4% aqueous NH ₃ 50% Select the reagent used Ammonia	Concentration of reagent injected (C _{inj})	10	percent	Densities of typical SI	NCR reagents:
Estimated equipment life 20 Years 29.4% aqueous NH ₃ 50 Years 50 Years 29.4% aqueous NH ₃ 50 Years 20 Years	Number of days reagent is stored (t _{storage})	14	days	50% urea sc	Jution 7
Select the reagent used Ammonia	Estimated equipment life	20	Years	29.4% aquec	ous NH ₃ 56
	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	CEPCI = Chemical Engineerir
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	

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

1 lbs/ft³ 6 lbs/ft³

ing Plant Cost Index

Data Sources for Default Values Used in Calculations:

			If you used
Data Flement	Default Value	Sources for Default Value	and the ref
Reagent Cost	\$0.293/gallon of	U.S. Geological Survey, Minerals Commodity Summaries, January 2017	(\$0.554/ga
	29% Ammonia	(https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	U.S. Geolog https://pub \$/gallon pr (510 \$/ton SOL / ft3 SC
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 \$/k U.S. Energy for MN indu https://ww pmt 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 Applica
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applica
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applica
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, Powe Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	r
Interest Rate	3.25	Default bank prime rate	(3.5%) Bank prime listed unde https://ww

your own site-specific values, please enter the value used erence source . . .

llon of 29% Ammonia)

gical Survey, Minerals Commodity Summaries, 2021

os.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. ice was back calculated.

NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb OL) / (7.48052 gal SOL / ft3 SOL) = \$0.554/gallon of 29%

(Wh)

Information Administration. Electric Power, January 2022 ustrial users. Available at: w.eia.gov/electricity/monthly/epm_table_grapher.php?t=e

able

able

able

e rate is as of March 2, 2021 and is available as the rates r 'bank prime loan' at w.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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$	20	lb/hour
	(whre SR = 1 for NH ₃ ; 2 for Urea)		
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	2 200	gallons (storage needed to store a 14 day reagent supply
	Density =	3,200	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

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 $(q_w) =$	$(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$	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 (Δ ash) =	(Δfuel x %Ash x 1x10 ⁶)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cos 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} = 2	20,000 x (B _{MW} x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF		
For Fuel Oil and Natural Gas-Fired Utility Boilers	:		
SNC	$R_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$		
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 _{cos}	_t = 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x 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:			
$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$			
For Fuel Oil and Natural Gas-Fired Utility Boilers:			
$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_{x}Removed/hr)^{0.12} \times RF$			
For Coal-Fired Industrial Boilers:			
$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$			
For Fuel Oil and Natural Gas-Fired Industrial Boilers:			
$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$			

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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$18,736 in 2019 dollars
Annual Electricity Cost =	$P x Cost_{elect} x t_{op} =$	\$960 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$241 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$1,708 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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?	ial 🔻	What type of fuel does the unit burn? Natural Gas		
Is the SCR for a new boiler or retrofit of an existing boiler?				
Please enter a retrofit factor between 0.8 and 1.5 based on the level of diff projects of average retrofit difficulty.	iculty. Enter 1 for 1			
Complete all of the highlighted data fields:				
What is the maximum heat input rate (QB)?	398.0 MMBtu/hour	Not applicable to units burning fuel oil or natural gas Type of coal burned: Not Applicable		
What is the higher heating value (HHV) of the fuel?	1,020 Btu/scf	Enter the sulfur content (%S) = percent by weight		
What is the estimated actual annual fuel consumption?	1,414,842,703 scf/Year	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.		
Enter the net plant heat input rate (NPHR)	8.2 MMBtu/MW	Fraction in		
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW	Coal TypeCoal Blend%SHHV (Btu/lb)Bituminous01.8411,841Sub-Bituminous00.418,826Lignite00.826,685		
Plant Elevation	1129 Foot above sea level	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		



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_s	_{.cr})	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 _{en}	_{npty})	1
Outlet NO _x Emissions (NOx _{out}) from SCR	0.04 lb/MMBtu	80.0% Assumed Control	Ammonia Slip (Slip) provided by vend	dor	<mark>2</mark> ppm
Stoichiometric Ratio Factor (SRF)	1.050	emelency	Volume of the catalyst layers (Vol _{catal} (Enter "UNK" if value is not known)	_{lyst})	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.			Flue gas flow rate (Q _{fluegas}) (Enter "UNK" if value is not known)		144512 acfm
Estimated operating life of the catalyst (H _{catalyst})	20,000 hours				
Estimated SCR equipment life * For industrial boilers, the typical equipment life is between 20 and 25 years.	20 Years*		Gas temperature at the SCR inlet (T)		330 °F
		_	Base case fuel gas volumetric flow ra	ite factor (Q _{fuel})	484 ft ³ /min-MMBtu/hour
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of	29% and density of 56 lbs/cft are default		
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*	values for ammonia reagent. U	Iser should enter actual values for reagent, if		
Number of days reagent is stored (t _{storage})	14 days			Densities of typical	SCR reagents:
				50% urea solution 29.4% agueous NH	71 lbs/ft^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 = Chemic
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing catalyst	* \$227/cf is a defau
Catalyst cost (CC _{replace})	227.00	and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a de
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a

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.

cal Engineering Plant Cost Index

ault value for the catalyst cost based on 2016 prices. User should enter actual value,

efault value for the operator labor rate. User should enter actual value, if known.

a default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallon of 20%) (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

(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
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 =		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at sea level (P) =	2116 x [(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.

94.525641

Not applicable; factor applies only to coal-fired boilers

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	(A) ^{0.5}	13.2	feet
reactor =	(A _{SCR})	13.2	leet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	94	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent

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 1

Capital Recovery Factor:

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

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

14 day reagent supply rounded to t

Density =

t (MW) = 17.03 g/mole 56 lb/ft³

Cost Estimate

Total Capital Investment (TCI)

	TCI for Oil and Natural Gas Boilers	
For Oil and Natural Gas-Fired Utility Boilers bet	ween 25MW and 500 MW:	
	TCI = 86,380 x (200/B _{MW}) ^{0.35} x B _{MW} x ELEVF x RF	
For Oil and Natural Gas-Fired Utility Boilers >50	00 MW:	
	TCI = 62,680 x B _{MW} x ELEVF x RF	
For Oil-Fired Industrial Boilers between 275 an	d 5,500 MMBTU/hour :	
	TCI = 7,850 x (2,200/Q _B) ^{0.35} x Q _B x ELEVF x RF	
For Natural Gas-Fired Industrial Boilers betwee	n 205 and 4,100 MMBTU/hour :	
	TCI = 10,530 x (1,640/Q _B) ^{0.35} x Q _B x ELEVF x RF	
For Oil-Fired Industrial Boilers >5,500 MMBtu/	hour:	
	TCI = 5,700 x Q_B x ELEVF x RF	
For Natural Gas-Fired Industrial Boilers >4,100	MMBtu/hour:	
	TCI = 7,640 x Q_B x ELEVF x 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?
Is the SNCR for a new boiler or retrofit of an existing boiler?	etrofit 🔹	
Please enter a retrofit factor equal to or greater than 0.84 based difficulty. Enter 1 for projects of average retrofit difficulty.	on the level of 1	
Complete all of the highlighted data fields:		
		Provide the following information for coal-fired boilers:
What is the maximum heat input rate (QB)?	248 MMBtu/hour	Type of coal burned: Sub-Bituminous
What is the higher heating value (HHV) of the fuel?	8,690 Btu/lb	Enter the sulfur content (%S) = 0.33 percent by wei
		Select the appropriate SO ₂ emission rate:
What is the estimated actual annual fuel consumption?	66,810,000 lbs/Year	Ash content (%Ash): 5 33 percent by wei
Is the boiler a fluid-bed boiler?	No 🔻	
		For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	Note: The table below is pre-populated with default values enter the actual values for these parameters in the table be parameter is not known, you may use the default values pro-
		Fraction in
If the NPHP is not known use the default NPHP value:		Coal Blend %S
if the NFTIX is not known, use the default NFTIX value.	Coal 10 MMBtu/MW	Sub-Bituminous 0 0.41
	Fuel Oil 11 MMBtu/MW Natural Gas 8.2 MMBtu/MW	Lignite 0 0.82
		Please click the calculate button to calculate weighted values based on the data in the table above.



ight

for HHV, %S, %Ash and cost. Please elow. If the actual value for any ovided. Table

		Fuel Cost
%Ash	HHV (Btu/lb)	(\$/MMBtu)
9.23	11,841	2.4
5.84	8,826	1.89
13.6	6,626	1.74

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	256 days	Plant Elevation	250	Feet above sea
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 (p _{stored})	56 lb/ft ³			
Concentration of reagent injected (C _{inj})	10 percent	Densities of typical SI	NCR reagents:	
Number of days reagent is stored (t _{storage})	14 days	50% urea sc	olution	71 lb
Estimated equipment life	20 Years	29.4% aquec	ous NH ₃	56 lb
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	CEPCI = Chemical Engineering F
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*	

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.

level

os/ft³ os/ft³

Plant Cost Index

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used you used and the re
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 U.S. Geological https://pubs.us \$/gallon price v (510 \$/ton NH3 SOL / ft3 SOL) /
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 Info for MN industri https://www.e pmt 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 Info Table 7.4. Publi https://www.e
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 listed under 'ba https://www.fe

r own site-specific values, please enter the value eference source...

of 29% Ammonia)

Survey, Minerals Commodity Summaries, 2021 gs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. vas back calculated.

8) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb / (7.48052 gal SOL / ft3 SOL) = \$0.554/gallon of 29%

ormation Administration. Electric Power, January 2022 al users. Available at: ia.gov/electricity/monthly/epm_table_grapher.php?t=e

)

ormation Administration. Electric Power Annual 2020. shed March 2022. Available at: ia.gov/electricity/annual/pdf/epa.pdf.

e is as of March 2, 2021 and is available as the rates ink prime loan' at ederalreserve.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 =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	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 fr
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	plants located at elevations
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

Calculated Value Parameter Equation Units 37 lb/hour 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) Reagent Usage Rate (m_{sol}) = 129 lb/hour $m_{reagent}/C_{sol} =$ 17.3 gal/hour (m_{sol} x 7.4805)/Reagent Density = 5,900 gallons (storage needed to store a 14 day reagent supply rounded (m_{sol} x 7.4805 x t_{storage} x 24 hours/day)/Reagent Estimated tank volume for reagent storage = up to the nearest 100 gallons) Density =

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	(0.47 x NOx _{in} x NSR x Q _B)/NPHR =	4.8	kW/hour
Water Usage:			
Water consumption (q _w) =	$(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$	29	gallons/hour
Fuel Data:			
Additional Fuel required to evaporate water in	Hy x m _{reagent} x $((1/C_{ini})-1) =$	0.30	MMBtu/hour
injected reagent (ΔFuel) =	reagent (() - m) /		
Ash Disposal:			
Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1x10 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:	
	$TCI = 1.3 x (SNCR_{cost} + BOP_{cost})$
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} = 2	20,000 x (B _{MW} x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF
For Fuel Oil and Natural Gas-Fired Utility Boilers	
SNCF	$R_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers:	
SNCR _{cost} = 220	0,000 x (0.1 x Q_B x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF
For Fuel Oil and Natural Gas-Fired Industrial Boil	lers:
SNCR _{cos}	_t = 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x RF
SNCR Capital Costs (SNCR _{cost}) =	\$997,859 in 2019 dollars
	Air Pre-Heater Costs (APH _{cost})*
For Coal-Fired Utility Bollers:	(2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2
APH _{co}	$_{st} = 69,000 \times (B_{MW} \times HRF \times COaIF)^{200} \times AHF \times RF$
For Coal-Fired Industrial Boilers:	(2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2
APH _{cost} :	= 69,000 x (0.1 x Q_B x HRF x CoalF) ²⁰⁰ x AHF x RF
Air Dro Hester Cests (ADH) -	¢0 in 2010 dellars
AIF Pre-Heater Costs (APH _{cost}) =	SU IN 2019 dollars
sulfur dioxide.	
	Balance of Plant Costs (BOP _{cost})
For Coal-Fired Utility Boilers:	
BOP _{cost} = 32	20,000 x $(B_{MW})^{0.33}$ x $(NO_x Removed/hr)^{0.12}$ x BTF x RF
For Fuel Oil and Natural Gas-Fired Utility Boilers	:
BOP _{cost} =	^{213,000} x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x RF
For Coal-Fired Industrial Boilers:	
BOP _{cost} = 320	,000 x (0.1 x Q _B) ^{0.33} x (NO _x Removed/hr) ^{0.12} x BTF x RF
For Fuel Oil and Natural Gas-Fired Industrial Boil	lers:
BOP _{cost} = 22	13,000 x (Q _B /NPHR) ^{0.33} x (NO _x Removed/hr) ^{0.12} x 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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$26,415 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$1,110 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$339 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$1,594 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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) \bullet percent by weight

Enter the following data for your combustion unit	t:							
Is the combustion unit a utility or industrial boiler?	Industrial	•			Wha	it 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 projects of average retrofit difficulty.	level of difficul	ty. Enter 1 fo	or	1				
Complete all of the highlighted data fields:								
					Prov	ide the following inform	mation for coa	I-fired boilers:
What is the maximum heat input rate (QB)?			248	MMBtu/hour	Туре	e of coal burned:	Sub-Bitumir	nous 🔻
What is the higher heating value (HHV) of the fuel?			8,690	Btu/lb	Ente	r the sulfur content (%	S) =	0.33
What is the estimated actual annual fuel consumption?		66,8	<mark>10,000</mark>	lbs/Year				
					For	Note: The table be these parameters i	os: low is pre-pop in the table be	ulated with de low. If the actu
Enter the net plant heat input rate (NPHR)			10	MMBtu/MW	_	default values prov	nueu.	
						Coal Typ	De	Fraction in Coal Blend
If the NPHR is not known, use the default NPHR value:		Fuel Type Coal Fuel Oil Natural Gas		Default NPHR 10 MMBtu/MW 11 MMBtu/MW 8 2 MMBtu/MW		Bitumino Sub-Bitumi Lignite	ous nous e	0 0 0
						Please click the cal values based on th	culate button e data in the t	to calculate we able above.
Plant Elevation			250	Feet above sea level	 For	coal-fired boilers, you	u may use eit	her Method 1
					cata and	lyst replacement cos 86 on the Cost Estim	t. The equat ate tab. Plea	ions for both ase select you

fault values for HHV and %S. Please enter the actual values for al value for any parameter is not known, you may use the



Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	256 days	Number of SCR reactor chambers (n _{scr})	1
Number of days the boiler operates (t_{plant})	256 days	Number of catalyst layers (R _{layer})	3
Inlet NO _x Emissions (NOx _{in}) to SCR	0.39 Ib/MMBtu	Number of empty catalyst layers (R _{empty})	1
Outlet NO _x Emissions (NOx _{out}) from SCR	0.06 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	<mark>2</mark> ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	650 °F
* For industrial boliers, the typical equipment life is between 20 and 25 years.		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*	*The reagent concentration of 29% and density of 56 lbs/cft are default	
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*	values for ammonia reagent. User should enter actual values for reagent, if	
Number of days reagent is stored (t _{storage})	14 days	Densities of t	vpical SCR reagents:
		50% urea solu 29.4% aqueou	ition 71 lbs/ft ³ Is 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 Ent	ter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical
Annual Interest Rate (i)	3.5 Per	rcent	
Reagent (Cost _{reag})	0.554 \$/g	gallon for 29% ammonia	_
Electricity (Cost _{elect})	0.0844 \$/k	xWh	
	\$/0	cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a default
Catalyst cost (CC _{replace})	227.00 cat	alyst and installation of new catalyst	if known.
Operator Labor Rate	60.00 \$/ł	nour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00 hou	urs/day*	* 4 hours/day is a de

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

efault value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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 G	as
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 =	$NOx_{in} \times EF \times Q_B =$	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; e	levation f
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6] ^{5.256} x (1/144)* =	14.6	psia	apply to plants lo 500 feet.	cated at
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		1	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at

https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

factor does not elevations below

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 (Volumeter) =			
, 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	()0.5	10.1	foot
reactor =	(A _{SCR})	12.1	leet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	52	feet

Reagent Data:

Type of reagent used

Ammonia

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

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 1

Capital Recovery Factor:

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

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

14 day reagent supply rounded to the n

Defisity – So ib/it

gent (MW) = Density = 7.03 g/mole 56 lb/ft³

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 x (NRF) ^{0.2} x (B _{MW} x HRF x CoalF) ^{0.92} x ELEVF x 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 x (NO x_{in} x B _{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NOx _{in} x Q _B x EF) ^{0.25} x 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 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q_B x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH _{cost}) =		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers that	t 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 x $(B_{MW} x HRFx CoalF)^{0.42} x ELEVF x RF$

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

BPC = 529,000 x $(0.1 \times Q_B \times CoalF)^{0.42}$ ELEVF x 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 =	$m_{sol} \times Cost_{reag} \times t_{op} =$	\$22,453 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$33,070 in 2019 dollars
Annual Catalyst Replacement Cost =		\$19,034 in 2019 dollars
For coal-fired boilers, the following methods		
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 dir enter <1 for less difficult retrofits.	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.				
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)? *HHV is the weighted average value calculated using the values entered in the	Btu/lb e coal blend composition table.	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above			
What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in the What is the estimated actual annual MWh output?	Btu/lb e coal blend composition table. 67,065 MWh	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above			
What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in the What is the estimated actual annual MWh output? Waste from a WFDG system disposed in an onsite or offsite landfill?	Btu/lb e coal blend composition table. 67,065 MWh ffsite Landfill	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above			

Enter the following design parameters for the proposed FGD System:

6122	Hours		Plant Elevation		250
6122	Hours				
1					
1.5					
30	Years				
30	Years				
6	Years				
2019					
607.5	Enter the CEPCI value for	or 2019 541.7	2016 CEPCI*		
	6122 6122 1 1.5 30 30 6 4 2019 607.5	6122 Hours 6122 Hours 1 1.5 30 Years 30 Years 6 Years 6 Years 2019 607.5 Enter the CEPCI value for	6122 Hours 6122 Hours 1 1.5 30 Years 30 Years 6 Years 6 Years 541.7	6122 Hours Plant Elevation 6122 Hours 1 1 1.5 30 Years 30 Years 6 Years 6 6 Years 2019 607.5 Enter the CEPCI value for 2019 541.7 2016 CEPCI*	6122 Hours Plant Elevation 6122 Hours 1 1.5 30 Years 30 Years 6 Years 6 Years 2019 607.5 Enter the CEPCI value for 2019 541.7 2016 CEPCI*

Annual Interest Rate (i)

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	30.00	\$/ton
waste Disposal cost (cost _{waste})	50.00	
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.

3.5 Percent

0 Feet above sea level

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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. Availabl 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. Availabl 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. Availabl 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. Availabl at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

	If you used your own site-specific values, please enter the value used
e	
e	
	(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=ep mt_5_6_a
e	
•	
	(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/.
e	

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 =	$SO_{2in} \times EF \times Q_B =$	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
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	apply to plants located at elevations below 500 feet.
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) =	$i (1+i)^n / (1+i)^n - 1 =$	0.0544
	Where n = Equipment Life and i= Interest Rate	

Waste Generation and Lime, Water and Power Consumption Rates:

Parameter	Equation	Calculated Value	Uni
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	kga
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	ton
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/ł

:S	
llons/hour	
s/hour	
iour	

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 x 98,000 x ELEVF		
For Coal-Fired Utility Boilers 50 and 600 MW : ABS _{co}	$_{ost} = 637,000 \text{ x (A)}^{0.716} \text{ x (CoalF x HRF)}^{0.6} \text{ x (S/4)}^{0.01} \text{ x ELEVF x RF}$		
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 x 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 x A x 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 =	$P \times Cost_{elect} \times t_{op} =$	\$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? Please enter a retrofit factor. Enter 1 for projects of average dif enter <1 for less difficult retrofits.	Retrofit	s >1 for more difficult	t retrofits and	1	
Directio	ons: 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	<u>OR</u>	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	e coal blend composition	Btu/lb table.	*Note: You do n HHV since you e Ib/MMBtu abov	not need to enter a value for the entered SO2 emissions in re	
	What is the estimated actual annual MWh output?	67,065	MWh]		
	Waste from a WFDG system disposed in an onsite or offsite landfill?	fsite 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
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 2	019 541.7	2016 CEPCI*		

Annual Interest Rate (i)

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	30.00	\$/ton
waste Disposal cost (cost _{waste})	50.00	
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.

3.5 Percent

0 Feet above sea level
Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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. Availabl 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. Availabl 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. Availabl 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. Availabl at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

	If you used your own site-specific values, please enter the value used
e	
e	
-	(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=ep mt_5_6_a
e	
	(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/.
e	

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 =	$SO_{2in} \times EF \times Q_B =$	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
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	does not apply to plants located at
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		1

* 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) =	$i(1+i)^{n}/(1+i)^{n} - 1 =$	0.0544	Wet FGD System
	Where n = Equipment Life and i= Interest Rate		
			Mercury Monitor
		0.1877	for Wastewater
			Treatment System

Parameter	Equation	Calculated Value	U
Electricity Usage:			
Electricity Consumption (P) =	0.0112e ^{0.155xS} x CoalF x HRF x A x 1,000 =	304	k
Water Usage:			┢
Water consumption (q _{water}) =	[(1.674 x S + 74.68) x A x CoalF x HRF]/1,000	2.0	k
Limestone Usage:			┢
Limestone consumption rate (Q _{Limestone}) =	[17.52 x A x S x HRF]/2,000] x (EF/0.98) =	0.05	t
Waste Generation:			┢
Waste generation rate (q _{waste}) =	[1.811 x Q _{Limestone} x (EF/0.98) =	0.1	t
Wastewater Flow Rate:			F
Wastewater flow rate (F) =	A x (0.4 gallons/min/MW) =	9	g

Jnits

W

gallons/hour

ons/hour

ons/hour

allons/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 a

	Wet FGD Capital Costs (ABS _{cost})
	$ABS_{cost} = 584,000 \text{ x (A)}^{0.716} \text{ x (CoalF x HRF)}^{0.6} \text{ x (S/2)}^{0.02} \text{ x ELEVF x RF}$
Wet FGD Capital Costs (ABS _{cost}) =	\$6,346,285 in 2019 dollars

	Reagent Preparation Costs (RPE _{cost})	
	RPE _{cost} = 202,000 x A ^{0.716} x (S x HRF) ^{0.3} x RF	
Reagent Preparation (RPE _{cost}) =		\$1,433,295 in 2019 dollar

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}) =

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

\$631,830 in 2019 dollars

t offsite landfill

	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

Tota	al Annual	Cost (T/	AC)	

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 Wa	ste Disposal Cost + Annual Auxiliary Powe
Annual Maintenance Cost =	0.015 x TCI =	\$617,923
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	\$187,200
Annual Reagent Cost =	$Q_{limestone} \times Cost_{Limestone} \times t_{op} =$	\$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 =	$q_{waste} \times Cost_{fuel} \times t_{op} =$	\$8,423
Annual Wastewater Treatment Cost =	(6.3225F + 472,080) x 0.958 x CFtotal x ESC =	\$161,811 (w
Replacement Cost for Mercury Monitor =	CF _{mm} x MM _{Cost} =	\$18,770 (re
Direct Annual Cost =		\$1,105,381 in

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

	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 20

t offsite landfill

er Cost + Annual Wastewater

vith disposal at offsite landfill) eplaced once every 6 years.) 2019 dollars

2019 dollars

019 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?	ndustrial 🗸	What type of fuel does the unit burn?
Is the SNCR for a new boiler or retrofit of an existing boiler?		
Please enter a retrofit factor equal to or greater than 0.84 based on t difficulty. Enter 1 for projects of average retrofit difficulty.	he level of 1	
Complete all of the highlighted data fields:		
		Provide the following information for coal-fired boilers:
What is the maximum heat input rate (QB)?	216 MMBtu/hour	Type of coal burned: Sub-Bituminous
What is the higher heating value (HHV) of the fuel?	8,690 Btu/lb	Enter the sulfur content (%S) = 0.33 percent by weight
		or Select the appropriate SO ₂ emission rate: Not Applicable V
What is the estimated actual annual fuel consumption?	63,678,000 lbs/Year	
Is the boiler a fluid-bed boiler?	No 🔻	Ash content (%Ash): 5.33 percent by weight
		For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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.
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MW	Colar Biend Composition FableFraction in Coal BlendFraction in %SFuel Cost %AshBituminous01.849.2311,8412.4Sub-Bituminous00.415.848,8261.89Lignite00.8213.66,6261.74
	Natural Gas 8.2 MMBtu/MW	Please click the calculate button to calculate weighted values based on the data in the table above.

		Fuel Cost
%Ash	HHV (Btu/lb)	(\$/MMBtu)
9.23	11,841	2.4
5.84	8,826	1.89
13.6	6,626	1.74

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	283 days	Plant Elevation	250 Feet above sea
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		
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	Densities of typical S	NCR reagents:
Number of days reagent is stored (t _{storage})	14 days	50% urea s	olution 71 lb
Estimated equipment life	20 Years	29.4% aque	bus NH ₃ 56 lb
Select the reagent used	Ammonia 🔻		

Enter the cost data for the proposed SNCR:

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

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.

level

os/ft³ os/ft³

Plant Cost Index

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used you used and the re
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 U.S. Geological https://pubs.us \$/gallon price v (510 \$/ton NH3 SOL / ft3 SOL) /
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 Info for MN industri https://www.e pmt 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 Info Table 7.4. Publi https://www.e
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 listed under 'ba https://www.fe

r own site-specific values, please enter the value eference source...

of 29% Ammonia)

Survey, Minerals Commodity Summaries, 2021 gs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. vas back calculated.

8) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb / (7.48052 gal SOL / ft3 SOL) = \$0.554/gallon of 29%

ormation Administration. Electric Power, January 2022 al users. Available at: ia.gov/electricity/monthly/epm_table_grapher.php?t=e

)

ormation Administration. Electric Power Annual 2020. shed March 2022. Available at: ia.gov/electricity/annual/pdf/epa.pdf.

e is as of March 2, 2021 and is available as the rates ink prime loan' at ederalreserve.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 =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	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 fr
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	plants located at elevations
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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m _{reagent}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOX} \times SR) =$	27	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
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	4 200	gallons (storage needed to store a 14 day reagent supply rounded
	Density =	4,300	up to the nearest 100 gallons)

Capital Recovery Factor:

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

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) =	$(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$	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:		
	$TCI = 1.3 x (SNCR_{cost} + APH_{cost} + BOP_{cost})$	
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} = 2	20,000 x (B _{MW} x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF
For Fuel Oil and Natural Gas-Fired Utility Boilers	
SNCF	$R_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers:	
SNCR _{cost} = 220	0,000 x (0.1 x Q_B x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF
For Fuel Oil and Natural Gas-Fired Industrial Boil	lers:
SNCR _{cos}	_t = 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x RF
SNCR Capital Costs (SNCR _{cost}) =	\$941,608 in 2019 dollars
	Air Pre-Heater Costs (APH _{cost})*
For Coal-Fired Utility Bollers:	(2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2
APH _{cos}	$_{st} = 69,000 \times (B_{MW} \times HRF \times COaIF)^{200} \times AHF \times RF$
For Coal-Fired Industrial Bollers:	(2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2, 2
APH _{cost} =	= 69,000 x (0.1 x Q_B x HRF x CoalF) ²⁰⁰ x AHF x RF
Air Dro Hester Costs (ADH) -	¢0 in 2010 dellars
AIF Pre-Heater Costs (APH _{cost}) =	SU IN 2019 dollars
sulfur dioxide.	
	Balance of Plant Costs (BOP _{cost})
For Coal-Fired Utility Boilers:	
BOP _{cost} = 32	20,000 x $(B_{MW})^{0.33}$ x $(NO_x Removed/hr)^{0.12}$ x BTF x RF
For Fuel Oil and Natural Gas-Fired Utility Boilers	:
BOP _{cost} =	^{213,000} x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x RF
For Coal-Fired Industrial Boilers:	
BOP _{cost} = 320	,000 x (0.1 x Q _B) ^{0.33} x (NO _x Removed/hr) ^{0.12} x BTF x RF
For Fuel Oil and Natural Gas-Fired Industrial Boil	lers:
BOP _{cost} = 22	13,000 x (Q _B /NPHR) ^{0.33} x (NO _x Removed/hr) ^{0.12} x 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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$22,150 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$931 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$284 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$1,337 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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	•			Wha	t type of fuel does the unit bu	rn?	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 projects of average retrofit difficulty.	level of difficu	lty. Enter 1 fo	r	1]			
Complete all of the highlighted data fields:								
					Prov	ide the following information for	or coal-fired b	oilers:
What is the maximum heat input rate (QB)?			216	MMBtu/hour	Туре	of coal burned: Sub-	Bituminous	•
What is the higher heating value (HHV) of the fuel?			8,690	Btu/lb	Ente	r the sulfur content (%S) =	0.33	\$ F
What is the estimated actual annual fuel consumption?		63,67	<mark>78,000</mark>	lbs/Year	1			
					For u	Inits burning coal blends: Note: The table below is pr these parameters in the tal default values provided.	e-populated v ble below. If th	vith de ne actu
Enter the net plant heat input rate (NPHR)			10	MMBtu/MW				
						Coal Type	Fraction Coal Ble	n in end
If the NPHR is not known, use the default NPHR value:		Fuel Type Coal Fuel Oil Natural Gas		Default NPHR 10 MMBtu/MW 11 MMBtu/MW 8.2 MMBtu/MW		Bituminous Sub-Bituminous Lignite		0 0 0
				· · ·		Please click the calculate be values based on the data in	utton to calcul h the table abo	ate we ve.
Plant Elevation			250	Feet above sea level] For	coal-fired boilers, you may u	se either Me	thod 1
					cata and	lyst replacement cost. The e 86 on the Cost Estimate tak	equations for b. Please sele	both ct you

022-07-21)

percent by weight

fault values for HHV and %S. Please enter the actual values for al value for any parameter is not known, you may use the

%S		HHV (Btu/lb)	
	1.84	11,841	
	0.41	8,826	
	0.82	6,685	
ighted ave	erage		
L or Meth methods	od 2 to are shc	calculate the own on rows 85	Method 1
r preferr	ed meth	nod:	O Method 2
P			O Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	283 days	Number of SCR reactor chambers (n _{scr})	1	
Number of days the boiler operates (t_{plant})	283 days	Number of catalyst layers (R _{layer})	3	
Inlet NO _x Emissions (NOx _{in}) to SCR	0.33 Ib/MMBtu	Number of empty catalyst layers (R _{empty})	1	
Outlet NO _x Emissions (NOx _{out}) from SCR	0.05 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
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	650 (۶
* For industrial boilers, the typical equipment life is between 20 and 25 years.		Pace case fuel gas volumetric flow rate fact.	ter (0,) 516	ft ³ /min-MMBtu/hour
		Base case ruer gas volumente now rate racto	tor (Q _{fuel})	
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default		
Density of reagent as stored (ρ_{stored})	56 Ib/cubic feet*	values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.		
Number of days reagent is stored (t _{storage})	14 days	Densit	ities of typical SCR reagents:	
		50% u	urea solution	71 lbs/ft ³
		29.4%	∕aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Select the reagent used

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemica
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a defaul
Catalyst cost (CC _{replace})	227.00	catalyst and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a d

▼

Ammonia

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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 G	as
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	1	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	59.78	lb/hour	1	
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		1	
Volumetric flue gas flow rate (q _{flue gas}) =	Q _{fuel} x QB x (460 + T)/(460 + 700)n _{scr} =	106,652	acfm	1	
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; e	levation f
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6] ^{5.256} x (1/144)* =	14.6	psia	apply to plants lo 500 feet.	cated at
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.

factor does not elevations below

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}) =			
, 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	()0.5	11.2	foot
reactor =	(A _{SCR})	11.5	leet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	52	feet

Reagent Data:

Type of reagent used

Ammonia

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

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 1

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	123.52	kW
	where A = (0.1 x QB) for industrial boilers.		

14 day reagent supply rounded to the n

Defisity – So ib/it

gent (MW) = Density = 7.03 g/mole 56 lb/ft³

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers			
For Coal-Fired Boilers:			
	TCI = 1.3 x (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	

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

	SCR Capital Costs (SCR _{cost})	
For Coal-Fired Utility Boilers >25 MW:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (B_{MW} \text{ x} HRF \text{ x} CoalF)^{0.92} \text{ x} ELEVF \text{ x} RF$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (0.1 \text{ x} Q_{B} \text{ x} \text{ CoalF})^{0.92} \text{ x} ELEVF \text{ x} RF$	
SCR Capital Costs (SCR _{cost}) =		\$6,217,367 in 2019 dollars
	Reagent Preparation Costs (RPC)	
For Coal-Fired Utility Boilers >25 MW:	0.25	
	RPC = 564,000 x (NOx _{in} x B_{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NOx _{in} x Q _B x EF) ^{0.25} x 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 x (B_{MM} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
· ··· ··· ···· ···· ····	APHC = 69,000 x (0.1 x Q_B x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH _{cost}) =		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers the	at 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 x $(B_{MW} x HRFx CoalF)^{0.42} x ELEVF x RF$

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

BPC = 529,000 x $(0.1 \times Q_B \times CoalF)^{0.42}$ ELEVF x 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 Method 1 (for all fuel types):	may be used to calcuate the catalyst replacement cost. $n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.3} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
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 di enter <1 for less difficult retrofits.	ifficulty. Enter values >1 for more difficult	t retrofits and 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
		7	
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 th	0.06 lb/MMBtu Btu/lb e coal blend composition table.	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above	
What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in th What is the estimated actual annual MWh output?	0.06 lb/MMBtu Btu/lb e coal blend composition table. 59,745 MWh	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above	
What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in th What is the estimated actual annual MWh output? Waste from a WFDG system disposed in an onsite or offsite landfill?	0.06 lb/MMBtu Btu/lb e coal blend composition table. 59,745 MWh ffsite Landfill	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above	

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t _{ABS})	6783	Hours		Plant Elevation	250
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			

Annual Interest Rate (i)

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	100.000	\$/monitor
	100,000	γποπιο

*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.

0 Feet above sea level

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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. Availabl 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. Availabl 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. Availabl 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. Availabl at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

	If you used your own site-specific values, please enter the value used
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-	(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=ep mt_5_6_a
e	
	(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/.
e	

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 =	$SO_{2in} \times EF \times Q_B =$	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
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	apply to plants located at elevations below 500 feet.
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) =	$i (1+i)^n / (1+i)^n - 1 =$	0.0544
	Where n = Equipment Life and i= Interest Rate	

Waste Generation and Lime, Water and Power Consumption Rates:

Parameter	Equation	Calculated Value	Uni
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	kga
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	ton
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/ł

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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 x 98,000 x ELEVF	
For Coal-Fired Utility Boilers 50 and 600 MW : ABS _{co}	$_{st} = 637,000 \text{ x (A)}^{0.716} \text{ x (CoalF x HRF)}^{0.6} \text{ x (S/4)}^{0.01} \text{ x ELEVF x RF}$	
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 x 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 x A x ELEVF
For Coal-Fired Utility Boilers betwee 50 and 600 MW :	
	$BOP_{cost} = 899,000 \text{ x } (A)^{0.716} \text{ x } (CoalF \text{ x } HRF)^{0.4} \text{ x } ELEVF \text{ x } RF$
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 =	$P \times Cost_{elect} \times t_{op} =$	\$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 d enter <1 for less difficult retrofits.	ifficulty. Enter values >1 for more difficult	t retrofits and 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		
Oulet SO ₂ Emissions (SO _{2out}) What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in th	0.03 lb/MMBtu Btu/lb e coal blend composition table.	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above	
Oulet SO ₂ Emissions (SO _{2out}) What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in th What is the estimated actual annual MWh output?	0.03 lb/MMBtu Btu/lb e coal blend composition table. 59,745 MWh	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above	
Oulet SO ₂ Emissions (SO _{2out}) What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in th What is the estimated actual annual MWh output? Waste from a WFDG system disposed in an onsite or offsite landfill?	0.03 lb/MMBtu Btu/lb e coal blend composition table. 59,745 MWh	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above	

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t _{ABS})	6783	Hours		Plant Elevation	250
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			

Annual Interest Rate (i)

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	100.000	\$/monitor
	100,000	γποπιο

*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.

0 Feet above sea level

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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. Availabl 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. Availabl 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. Availabl 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. Availabl at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

	If you used your own site-specific values, please enter the value used
e	
e	
-	(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=ep mt_5_6_a
e	
	(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/.
e	

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 =	$SO_{2in} \times EF \times Q_B =$	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
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	does not apply to plants located at
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		1

* 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) =	$i (1+i)^n / (1+i)^n - 1 =$	0.0544 Wet FGD S	ystem
	Where n = Equipment Life and i= Interest Rate		
		Mercury M	onitor
		0.1877 for Waster	water
		Treatment	System

Parameter	Equation	Calculated Value	ι
Electricity Usage:			
Electricity Consumption (P) =	0.0112e ^{0.155xS} x CoalF x HRF x A x 1,000 =	266	k
Water Usage:			t
Water consumption (q _{water}) =	[(1.674 x S + 74.68) x A x CoalF x HRF]/1,000	1.7	k
Limestone Usage:			t
Limestone consumption rate (Q _{Limestone}) =	[17.52 x A x S x HRF]/2,000] x (EF/0.98) =	0.05	t
Waste Generation:			t
Waste generation rate (q _{waste}) =	[1.811 x Q _{Limestone} x (EF/0.98) =	0.1	t
Wastewater Flow Rate:			t
Wastewater flow rate (F) =	A x (0.4 gallons/min/MW) =	7	g

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gallons/hour

ons/hour

ons/hour

allons/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 a

	Wet FGD Capital Costs (ABS _{cost})
	$ABS_{cost} = 584,000 \text{ x } (A)^{0.716} \text{ x } (CoalF \text{ x } HRF)^{0.6} \text{ x } (S/2)^{0.02} \text{ x } ELEVF \text{ x } RF$
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	203			

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}) =

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

)19 dollars

\$592,808 in 2019 dollars

t offsite landfill

		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 a
1			

	Tota	Annua	Cost (TAC)	
<u> </u>				

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 Was	te Disposal Cost + Annual Auxiliary Powe
Annual Maintenance Cost =	0.015 x TCI =	\$578,488
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	\$187,200
Annual Reagent Cost =	$Q_{\text{limestone}} \times \text{Cost}_{\text{Limestone}} \times t_{\text{op}} =$	\$5,249
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$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 (w
Replacement Cost for Mercury Monitor =	CF _{mm} x MM _{Cost} =	\$18,770 (re
Direct Annual Cost =		\$1,071,160 in

	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			

	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 20

t offsite landfill

er Cost + Annual Wastewater

vith disposal at offsite landfill) eplaced once every 6 years.) 2019 dollars

2019 dollars

019 dollars

Data Inputs (MPCA FFA Costs, Hibbing Public Utilities Commission, Boiler 7, SCR, 2022-07-21) ▼ percent by weight fault values for HHV and %S. Please enter the actual values for al value for any parameter is not known, you may use the

Enter the following data for your combustion unit	:							
Is the combustion unit a utility or industrial boiler?	Industrial	•			Wha	t type of fuel does tl	he 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 projects of average retrofit difficulty.	level of difficu	lty. Enter 1 for	r	1				
Complete all of the highlighted data fields:								
					Prov	ide the following info	ormation for co	oal-fired boilers:
What is the maximum heat input rate (QB)?			230 MN	1Btu/hour	Туре	of coal burned:	Lignite	•
What is the higher heating value (HHV) of the fuel?			<mark>4,450</mark> Btu	/lb	Ente	r the sulfur content (%S) =	0.02 p
What is the estimated actual annual fuel consumption?		105,72	2 <mark>8,000</mark> lbs,	/Year		N. I		
					For U	Note: The table to the table table to the table table to the table	pelow is pre-po s in the table b ovided.	opulated with def below. If the actua
Enter the net plant heat input rate (NPHR)			10 MN	/Btu/MW				
						Coal T	уре	Fraction in Coal Blend
If the NPHR is not known, use the default NPHR value:		Fuel Type Coal Fuel Oil Natural Gas	Def 10 11 8.2	ault NPHR MMBtu/MW MMBtu/MW MMBtu/MW		Bitumin Sub-Bitur Ligni	nous minous ite	0 0 0
						Please click the c values based on	alculate butto the data in the	n to calculate wei table above.
Plant Elevation			1440 Fee	t above sea level	For	coal-fired boilers, y	ou may use e	either Method 1
					cata and	lyst replacement co 86 on the <i>Cost Esti</i>	ost. The equa imate tab. Pl	ease select your



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	<mark>2</mark> ppm		
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet		
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	650 °F		
* For industrial boilers, the typical equipment life is between 20 and 25 years.		Base case fuel gas volumetric flow rate factor (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*	*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			
Number of days reagent is stored (t _{storage})	14 days	Densities	Densities of typical SCR reagents:		
		50% urea 29.4% aq	solution 71 lbs/ft ³ ueous NH ₃ 56 lbs/ft ³		

Enter the cost data for the proposed SCR:

Select the reagent used

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a default
Catalyst cost (CC _{replace})	227.00	catalyst and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a de

▼

Ammonia

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

efault value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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	i
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 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	0.1105	Fraction
Catalyst volume (Volume) =			
	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	()0.5	11 7	foot
reactor =	(A _{SCR})	11./	leet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	50	feet

Reagent Data:

Type of reagent used

Ammonia

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

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 1

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value Units	
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	132.60	kW
	where $A = (0.1 \times QB)$ for industrial boilers.		

14 day reagent supply rounded to the n

Defisity – So ib/it

gent (MW) = Density = 7.03 g/mole 56 lb/ft³

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:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (B_{MW} \text{ x} HRF \text{ x} CoalF)^{0.92} \text{ x} ELEVF \text{ x} RF$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	SCR _{cost} = 310,000 x (NRF) ^{0.2} x (0.1 x Q _B x CoalF) ^{0.92} x ELEVF x RF	
Γ		
SCR Capital Costs (SCR _{cost}) =		\$6,937,059 in 2019 dollars
	Reagent Prenaration Costs (RPC)	
For Coal-Fired Utility Boilers >25 MW:	Reagent reparation costs (Ri C)	
· · · · · · · · · · · · · · · · · · ·	RPC = 564,000 x (NOX _{in} x B _{MM} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NOx _{in} x Q _B x EF) ^{0.25} x RF	
Reagent Preparation Costs (RPC) =		\$1,384,659 in 2019 dollars
For Coal-Fired Litility Boilers >25MW:		
Tor courried officy boliers >25 www.	APHC = 69 000 x (B ₁ ,, x HRE x CoalE) ^{0.78} x AHE x RE	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
· · · · · · · · · · · · · · · · · · ·	APHC = 69,000 x (0.1 x Q _R x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH _{cost}) =		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers the	at 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 x $(B_{MW} x HRFx CoalF)^{0.42} x ELEVF x RF$

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

BPC = 529,000 x (0.1 x $Q_B x \text{ CoalF})^{0.42}$ ELEVF x 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 method 1 (for all fuel types):	ods may be used to calcuate the catalyst replacement cost. n _{scr} x Vol _{cat} x (CC _{replace} /R _{laver}) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers): $(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
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?	ndustrial 💌	What type of fuel does the unit burn?
Is the SNCR for a new boiler or retrofit of an existing boiler?		
Please enter a retrofit factor equal to or greater than 0.84 based on t difficulty. Enter 1 for projects of average retrofit difficulty.	he level of 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:		
		Provide the following information for coal-fired boilers:
What is the maximum heat input rate (QB)?	517 MMBtu/hour	Type of coal burned:
What is the higher heating value (HHV) of the fuel?	8,625 Btu/lb	Enter the sulfur content (%S) = 0.22 percent by weight
		Select the appropriate SO ₂ emission rate:
What is the estimated actual annual fuel consumption?	395,118,000 lbs/Year	
		Ash content (%Ash): 5.08 percent by weight
Is the boiler a fluid-bed boiler?	No 💌	
		For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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 Fuel Cost
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Case2.2 MMBtu/MW	Coal Blend %S %Ash HHV (Btu/lb) (\$/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:

			1	
Number of days the SNCR operates (t_{SNCR})	339	days	Plant Elevation	764 Feet above sea
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		*The NSR for a urea system may be calcula Control Cost Manual (as updated April 201	ted using equation 1.17 in Sectic 9).
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	Densities of typical S	NCR reagents:
Number of days reagent is stored (t _{storage})	14	days	50% urea s	olution 71 lbs
Estimated equipment life	20	Years	29.4% aque	ous NH ₃ 56 lbs
		-		
Select the reagent used	Urea	7		

Enter the cost data for the proposed SNCR:

Desired dollar-year CEPCI for 2019	2019 607.5 Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering
Annual Interest Rate (i) Fuel (Cost _{fuel})	3.5 Percent 1.9 \$/MMBtu 1.660 \$/gallen for a 50 percent solution of urea*	_
Water (Cost _{reag}) Electricity (Cost _{elect})	0.0042 \$/gallon* 0.0844 \$/kWh	-
Ash Disposal (for coal-fired boilers only) (Cost _{ash})	48.80 \$/ton*	

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.

level

ion 4, Chapter 1 of the Air Pollution



Plant Cost Index

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used you used and the re
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 Info for MN industri https://www.ei pmt 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 Info Table 7.4. Publi https://www.ei
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 listed under 'ba https://www.fe

r own site-specific values, please enter the value eference source . . .

ormation Administration. Electric Power, January 2022 al users. Available at: ia.gov/electricity/monthly/epm_table_grapher.php?t=e

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ormation Administration. Electric Power Annual 2020. shed March 2022. Available at: ia.gov/electricity/annual/pdf/epa.pdf.

e is as of March 2, 2021 and is available as the rates ink prime loan' at ederalreserve.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 =	$NOx_{in} \times EF \times Q_B =$	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
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	

666.6

* 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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$	125	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
Reagent Usage Rate (m _{sol}) =	m _{reagent} /C _{sol} =	250	lb/hour
	(m _{sol} x 7.4805)/Reagent Density =	26.4	gal/hour
Estimated tank volume for reagent storage =	(m _{sol} x 7.4805 x t _{storage} x 24 hours/day)/Reagent	8 000	gallons (storage needed to store a 14 day reagent supply
	Density =	8,900	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	(0.47 x NOx _{in} x NSR x Q _B)/NPHR =	9.0	kW/hour
Water Usage:			
Water consumption (q _w) =	$(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$	120	gallons/hour
Fuel Data:			
Additional Fuel required to evaporate water in	$Hv \times m_{response} \times ((1/C_{ini})-1) =$	1.01	MMBtu/hour
injected reagent (ΔFuel) =		1.01	
Ash Disposal:			
Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel x %Ash x 1x10^{6})/HHV =$	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} = 2	220,000 x (B _{MW} x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF			
For Fuel Oil and Natural Gas-Fired Utility Boilers	:			
SNC	R _{cost} = 147,000 x (B _{MW} x HRF) ^{0.42} x ELEVF x RF			
For Coal-Fired Industrial Boilers:				
SNCR _{cost} = 22	0,000 x (0.1 x Q _B x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF			
For Fuel Oil and Natural Gas-Fired Industrial Boi	lers:			
SNCR _{cos}	_t = 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x RF			
SNCR Capital Costs (SNCR _{cost}) =	\$1,814,402 in 2019 dollars			
	Air Pre-Heater Costs (APH _{cost})*			
For Coal-Fired Utility Boilers:				
APH _{co}	_{st} = 69,000 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x 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 bo sulfur dioxide.	ilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of			
	Balance of Plant Costs (BOP _{cost})			
For Coal-Fired Utility Boilers:				
BOP _{cost} = 32	20,000 x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x BTF x RF			
For Fuel Oil and Natural Gas-Fired Utility Boilers:				
$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_{x}Removed/hr)^{0.12} \times RF$				
For Coal-Fired Industrial Boilers:				
$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$				
For Fuel Oil and Natural Gas-Fired Industrial Boilers:				
$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$				
Balance of Plant Costs (BOP _{cost}) =	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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$288,344 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$5,010 in 2019 dollars
Annual Water Cost =	$q_{water} x Cost_{water} x t_{op} =$	\$3,295 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$12,686 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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?	ial 🔹	What type of fuel does the unit burn?	
Please enter a retrofit factor between 0.8 and 1.5 based on the level of diffi projects of average retrofit difficulty.	iculty. Enter 1 for 1		
Complete all of the highlighted data fields:			
What is the maximum heat input rate (QB)?	175 MMBtu/hour	Provide the following information for coal-fired boilers: Type of coal burned: Sub-Bituminous	
What is the higher heating value (HHV) of the fuel?	8,625 Btu/lb	Enter the sulfur content (%S) = 0.32 percent by weight	
What is the estimated actual annual fuel consumption?	42,518,000 lbs/year	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	
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW		
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW	Coal TypeCoal Blend%SHHV (Btu/lb)Bituminous01.8411,841Sub-Bituminous00.418,826Lignite00.826,685	
Plant Elevation	1440 Feet above sea level	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:	

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	211 days	Number of SCR reactor chambers (n _{scr})	1	
Number of days the boiler operates (t _{plant})	211 days	Number of catalyst layers (R _{layer})	3	
Inlet NO _x Emissions (NOx _{in}) to SCR	0.39 Ib/MMBtu	Number of empty catalyst layers (R _{empty})	1	
Outlet NO _x Emissions (NOx _{out}) from SCR	0.06 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
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	650	°F
* For industrial boilers, the typical equipment life is between 20 and 25 years.		- Base sace fuel gas volumetric flow rate facto	tor (O) 516	ft ³ /min-MMBtu/hour
		Base case ruel gas volumetric now rate facto	tor (Q _{fuel})	
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default		
Density of reagent as stored (ρ_{stored})	56 Ib/cubic feet*	values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.		
Number of days reagent is stored (t _{storage})	14 days	Densit	ities of typical SCR reagents:	
		50% ur	urea solution	71 lbs/ft ³
		29.4%	% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Select the reagent used

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemica
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a defaul
Catalyst cost (CC _{replace})	227.00	catalyst and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a de

▼

Ammonia

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	
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	
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.	(
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	

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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 =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	60.16	tons/year
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.

70.776526

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 (Volestalyst) =			
, 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	(A) ^{0.5}	10.2	foot
reactor =	(A _{SCR})	10.2	leet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent
		_

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

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	100.08	kW
	where A = (0.1 x QB) for industrial boilers.		

Density =

t (MW) = 17.03 g/mole 56 lb/ft³

14 day reagent supply rounded to t

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 Invoctment (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:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (0.1 \text{ x} Q_{B} \text{ x} \text{ CoalF})^{0.92} \text{ x} ELEVF \text{ x} RF$	
SCR Capital Costs (SCR _{cost}) =		\$5,393,867 in 2019 dollars
	Passant Proparation Costs (PPC)	
For Coal-Fired Litility Boilers >25 MW:		
Tor courried officty boliers >25 WWW.	RPC = 564,000 x (NOx _{in} x B _{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NOx _{in} x Q _B x EF) ^{0.25} x RF	
Peagent Proparation Costs (PPC) -		\$1.741.116 in 2019 dollars
	Air Pre-Heater Costs (APHC)*	
For Coal-Fired Utility Boilers >25MW:		
	APHC = 69,000 x $(B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH) -		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers the	at hurn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide	30 III 2019 dollars
	Balance of Plant Costs (BPC)	
For Coal-Fired Utility Boilers >25MW:		

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

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

BPC = 529,000 x (0.1 x $Q_B x \text{ CoalF})^{0.42}$ ELEVF x 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 meth	ods may be used to calcuate the catalyst replacement cost.	* Coloulation Mathed 1 colocted
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	b): $(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
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 co	st (A)				3,357,568
Installation - Standard Costs	95%	of nurchased equin	cost (B)				3 189 689
Installation - Site Specific Costs	5570						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, repla	acement parts,	, utilities, etc.		277,985
Total Annual Indirect Operating Costs		Sum indirect oper c	osts + capital re	ecovery cost			1,277,034
Total Annual Cost (Annualized Capital Cos	t + Operating	g 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
Instrumentation	2% of control device cost (A)	58 969
MN Sales Taxes	2% of control device cost (A) 6.9% of control device cost (A)	202 707
Ivin Sales Taxes	5.9% of control device cost (A)	202,707
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 Total Site Specific Costs	10.5% of DC + IC	1,218,983 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

e inico, eupprice, replacemente a tracte man	agement	
Replacement power from efficiency loss	NA 0.2% OFA efficiency drop per engineering estimates	81,567
NA	NA	-

NA	NA	-
NA	NA	-
Total Annual Direct Operating Co	osts	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 Ho	ours	5,77	4	
			Utilization Ra	ate:	78%	⁄⁄	
ltem	Unit Cost \$	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments

LNB-OFA Summary

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 c	ost (A)			9,921,386
Installation Standard Costs	740/					7 0 44 005
Installation - Standard Costs	/4%	of purchased equip	D 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 equir	p 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	, etc.	1,551,147		
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				
Total Annual Cost (Annualized Capital Cost	st)				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.

DSI Summary

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	m + 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 Ba	ags, 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 Mana	gement	

djusted TCI for Replacement Parts (Catalyst, Filter E	Bags, etc) for Capital Recovery Cost	21,539,732
otal Capital Investment (TCI) with Retrofit Factor	30%	28,001,651
PPERATING 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 Man	agement	
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
otal Annual Cost (Annualized Capital Cost + Operati	ng 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 Solid Waste Disposal 214.87 lb/hr SO21193.80 lb/hr Trona2,709 ton/yr DSI unreacted sorbent and reaction byproducts

Operating Cost Calculations

Utilization Rate	73%	Annual Ope	rating Hours	5,650			
	Unit	Unit of	Use	Unit of	Annual	Annual	Comments
ltem	Cost \$	Measure	Rate	Measure	Use*	Cost	
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	e Labor		NA	\$ 42,375	100% of Maintenance Labor
Utilities, Supplies, Replaceme	ents & Waste	e Management	t				
Electricity	0.076	\$/kwh	218.1 k\	V-hr	1,232,089	\$ 93,639	\$/kwh, 218.1 kW-hr, 5650 hr/yr, 73% utilization
Water			N/A g	om			
Compressed Air	0.467	\$/kscf	2.0 sc	fm/kacfm	99,384	\$ 46,447	\$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization
Cooling Water			N/A gr	om			
Solid Waste Disposal	41.32	\$/ton	0.5 to	n/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 ba	ags	N/A	\$ 195,479	\$/bag, 2,952 bags, 5650 hr/yr, 73% utilization

DSI Summary

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 00)1	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 devic	e cost (A)				25,990,134
Installation - Standard Costs	74%	of purchased e	quip 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 e	quip 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, supervis	ion, materials, re	placement par	rts, utilities, et	C.	1,013,681
Total Annual Indirect Operating Costs		Sum indirect op	er costs + capita	I recovery cos	t		8,605,244
Total Annual Cost (Annualized Capital Co	ost + 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.

SDA Summary

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 + r	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 (Å)	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 rees	10% of purchased equip cost (B)	2,599,013
Start-up	1% of purchased equip cost (B)	259,901
Performance test Model Studies	1% of purchased equip cost (B)	259,901
	10% of purchased equip cost (B)	-
Contingencies Total Indirect Capital Costs IC	52% of purchased equip cost (B)	2,599,013
Total mullect Capital Costs, iC		10,014,000
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 Ma	nagement	
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		-
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					
Blower, Baghouse	Flow acfm D P 200,800 1	in H2O 0.00	Efficiency Hp	kW 2,053,481	Electricity demand for new baghouse
Total				2,053,481	
Filter Bags					
Lime Use Rate	1.30 lb-mole CaO/lb-mol	e SO2	290.74 lb/hr Lime		
Solid Waste Disposal	1,214 ton/yr unreacted so	rbent and	reaction byproducts		

Operating Cost Calculations

Utilization Rate	73%	Annual Opera	ating Hours	5,650			
	Unit	Unit of	Use	Unit of	Annual	Annual	Comments
Item	Cost \$	Measure	Rate	Measure	Use*	Cost	
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 Maintenan	ce Labor		NA	\$ 42,375	100% of Maintenance Labor
Utilities, Supplies, Replacements	& Waste M	anagement					
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

SDA Summary

Data Input	s (MPCA FFA Costs, Northshore	e 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?
Is the SNCR for a new boiler or retrofit of an existing boiler?		
Please enter a retrofit factor equal to or greater than 0.84 based on th difficulty. Enter 1 for projects of average retrofit difficulty.	e level of 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:		Drovido the following information for coal fired bailors:
What is the maximum heat input rate (QB)?	765 MMBtu/hour	Type of coal burned:
What is the higher heating value (HHV) of the fuel?	8,625 Btu/lb	Enter the sulfur content (%S) = 0.22 percent by weight
		or Select the appropriate SO ₂ emission rate: Not Applicable
What is the estimated actual annual fuel consumption?	390,484,000 lbs/Year	A_{ch} contact (% A_{ch}): 5.08 percent by weight
Is the boiler a fluid-bed boiler?	No 🔻	Ash content (%Ash).
		For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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
If the NPHR is not known, use the default NPHR value:	Fuel Type Default NPHR	Fraction in Coal Blend %S %Ash HHV (Btu/lb) Fuel Cost (\$/MMBtu) Bituminous 0 1.84 9.23 11.841 2.4
	Coal 10 MMBtu/MW Fuel Oil 11 MMBtu/MW Natural Gas 8.2 MMBtu/MW	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
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 calculat Control Cost Manual (as updated April 2019	ed using equation 1.17 in Se).
Concentration of reagent as stored (C _{stored})	50	Percent	1	
Density of reagent as stored (ρ_{stored})	71	lb/ft ³		
Concentration of reagent injected (C _{inj})	10	percent	Densities of typical S	NCR reagents:
Number of days reagent is stored (t _{storage})	14	days	50% urea so	olution 7
Estimated equipment life	20	Years	29.4% aque	ous NH ₃ 5
Select the reagent used	Urea			

Enter the cost data for the proposed SNCR:

Desired dollar-year CEPCI for 2019	2019 607.5 Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineerir
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*	

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) = Administrative Charges Factor (ACF) =

0.015
0.03

e sea level

ection 4, Chapter 1 of the Air Pollution

71 lbs/ft³ 56 lbs/ft³

ing Plant Cost Index

Data Sources for Default Values Used in Calculations:

			If you used
Data Element	Default Value	Sources for Default Value	and the ref
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 \$/k U.S. Energy for MN indu https://ww
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 \$/MN U.S. Energy Table 7.4. P https://ww
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 listed unde https://ww

your own site-specific values, please enter the value used erence source . . .

(Wh)

v Information Administration. Electric Power, January 2022 ustrial users. Available at: vw.eia.gov/electricity/monthly/epm_table_grapher.php?t=e

/IBtu)

Published March 2022. Available at: ww.eia.gov/electricity/annual/pdf/epa.pdf.

e rate is as of March 2, 2021 and is available as the rates r 'bank prime loan' at w.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
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	

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* 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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$	237	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
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	16,800	gallons (storage needed to store a 14 day reagent supply
	Density =	10,800	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units
Electricity Usage:	$(0.47 \times NOx. \times NSR \times O_{-})/NPHR =$	17 1	kW/bour
		17.1	KWYHOU
Water Usage:			
Water consumption (q _w) =	$(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$	227	gallons/hour
Fuel Data:			
Additional Fuel required to evaporate water in	Hy x $m_{roadout}$ x ((1/C _{ini})-1) =	1.92	MMBtu/hour
injected reagent (ΔFuel) =			
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:		
	$TCI = 1.3 x (SNCR_{cost} + APH_{cost} + BOP_{cost})$	
For Fuel Oil and Natural Gas-Fired Boilers:		
	$TCI = 1.2 \times (SNCP \pm POP)$	
	$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$	
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	

 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} = 2	220,000 x $(B_{MW} \times HRF)^{0.42}$ x CoalF x BTF x ELEVF x RF	
For Fuel Oil and Natural Gas-Fired Utility Boilers	X	
SNC	R _{cost} = 147,000 x (B _{MW} x HRF) ^{0.42} x ELEVF x RF	
For Coal-Fired Industrial Boilers:		
SNCR _{cost} = 22	0,000 x (0.1 x Q _B x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF	
For Fuel Oil and Natural Gas-Fired Industrial Boi	lers:	
SNCR _{cos}	_{st} = 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x RF	
SNCR Capital Costs (SNCR _{cost}) =	\$2,138,973 in 2019 dollars	
		
	Air Pre-Heater Costs (APH _{cost})*	
For Coal-Fired Utility Boilers:		
APH _{co}	$_{st}$ = 69,000 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers:	0.70	
APH _{cost}	= 69,000 x (0.1 x Q _B x HRF x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH _{cost}) =	\$0 in 2019 dollars	
* Not applicable - This factor applies only to coal-fired bo sulfur dioxide	ilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of	
	Balance of Plant Costs (BOP _{cost})	
For Coal-Fired Utility Boilers:		
BOP _{cost} = 32	20,000 x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x BTF x RF	
For Fuel Oil and Natural Gas-Fired Utility Boilers	X.	
BOP _{cost} =	= 213,000 x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x RF	
For Coal-Fired Industrial Boilers:		
BOP _{cost} = 320	1,000 x (0.1 x Q _B) ^{0.33} x (NO _x Removed/hr) ^{0.12} x BTF x RF	
For Fuel Oil and Natural Gas-Fired Industrial Boi	lers:	
BOP _{cost} = 2	13,000 x (Q _B /NPHR) ^{0.33} x (NO _x Removed/hr) ^{0.12} x 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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$364,690 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$6,337 in 2019 dollars
Annual Water Cost =	$q_{water} x Cost_{water} x t_{op} =$	\$4,168 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$16,045 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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	1				
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 projects of average retrofit difficulty.	evel of difficu	ty. Enter 1 for	1.3	* NOTE: You must document why a retrofit factor of 1.3 is appro the proposed project.	priate for
Complete all of the highlighted data fields:					
What is the maximum heat input rate (QB)?		765 MMBtu/hour		Type of coal burned: Sub-Bituminous	T bollers:
What is the higher heating value (HHV) of the fuel?		8,6	25 Btu/lb	Enter the sulfur content (%S) =	0.22 p
What is the estimated actual annual fuel consumption?		390,484,0	<mark>00</mark> lbs/year	Ear units hurning coal blonds:	
				Note: The table below is pre-populate these parameters in the table below. I default values provided.	d with def f the actua
Enter the net plant heat input rate (NPHR)			<mark>10</mark> MMBtu/MW	Frac	tion in
If the NPHR is not known, use the default NPHR value:		Fuel Type Coal Fuel Oil Natural Gas	Default NPHR 10 MMBtu/MW 11 MMBtu/MW 8.2 MMBtu/MW	Bituminous Sub-Bituminous Lignite	0 0 0
				Please click the calculate button to cal values based on the data in the table a	culate wei above.
Plant Elevation		7	64 Feet above sea level	For coal-fired boilers, you may use either for coal-fired boilers, you may use either for catalyst replacement cost. The equations and 86 on the Cost Estimate tab. Please set	Vethod 1 for both r elect your



1 or Method 2 to calculate the methods are shown on rows 85 Ir preferred method:

- Method 1Method 2
- O Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	241 days	Number of SCR reactor chambers (n _{scr})	1
Number of days the boiler operates (t _{plant})	241 days	Number of catalyst layers (R _{layer})	3
Inlet NO _x Emissions (NOx _{in}) to SCR	0.60 Ib/MMBtu	Number of empty catalyst layers (R _{empty})	1
Outlet NO _x Emissions (NOx _{out}) from SCR	0.12 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	<mark>2</mark> ppm
Stoichiometric Ratio Factor (SRF)	0.525	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 0.525 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	650 °F
* For industrial boilers, the typical equipment life is between 20 and 25 years.		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*	*The reagent concentration of 50% and density of 71 lbs/cft are default	
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*	values for urea reagent. User should enter actual values for reagent, if different from the default values provided.	
Number of days reagent is stored (t _{storage})	14 days	Densities of typic	al SCR reagents:
		50% urea solution	n 71 lbs/ft ³
		29.4% aqueous N	H 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
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	1.660	\$/gallon for 50% urea*	* \$1.66/gallon is a de
Electricity (Cost _{elect})	0.0844	\$/kWh	
Catalyst cost (CC)	227.00	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default if known.
Operator Labor Bate	60.00	\$/hour (including henefits)*	* \$60/bour is a defa
Operator Labor Nate	00.00		
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a de

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.

I Engineering Plant Cost Index

efault value for 50% urea. User should enter actual value, if known.

t value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

efault value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	
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-	
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.	(
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	([

f you used your own site-specific values, please enter the value used and the reference source ...

(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

(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
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 x [(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.

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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 (Volumeter) =			
catalyst claime (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	()0.5	20.6	foot
reactor =	(A _{SCR})	20.0	leet
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) =

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

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	437.48	kW
	where A = (0.1 x QB) for industrial boilers.		

Density =

60.06 g/mole 71 lb/ft³

14 day reagent supply rounded to t

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 Canital 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:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (B_{MW} \text{ x} HRF \text{ x} CoalF)^{0.92} \text{ x} ELEVF \text{ x} RF$	
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) -		\$26,259,107 in 2019 dollars
Server Capital Costs (Serv _{cost}) =		
	Reagent Preparation Costs (RPC)	
For Coal-Fired Utility Boilers >25 MW:		
	RPC = 564,000 x (NO x_{in} x B_{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NOx _{in} x Q _B x EF) ^{0.25} x 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 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH _{cost}) =		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers the	at 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 x (B _{MW} x HRFx Co	oalF) ^{0.42} x ELEVF x RF
--	------------------------------------

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

BPC = 529,000 x (0.1 x $Q_B x$ CoalF)^{0.42} ELEVF x 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 metho	ds 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)	: $(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
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 c	ost (A)			10,887,688
Installation - Standard Costs	74%	of purchased equir	o 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	o 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				
Total Annual Cost (Annualized Capital Cost	st)				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.

DSI Summary

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) //	n i cuvilian cavinnant FC	8,933,488
Pulchased Equipment Costs (A) - Injection Syste	10% Included in vender estimate	002 240
Instrumentation	6 0% of control dovice cost (A)	693,349
	6.9% of control device cost (A)	014,177
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 B	ags, 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 Mana	gement	
Electricity N/A	0.08 \$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization	110,610 -
Compressed Air	0.47 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization	58,624

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
Fotal Annual Cost (Annualized Capital Cost + Ope	rating Cost)	5,628,525

N/A

-

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)

3.50%
20 years
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
Deement Hee & Oth	an On anatin n Oa ata		

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR270.18 lb/hr SO21501.10 lb/hr TronaSolid Waste Disposal3,481 ton/yr DSI unreacted sorbent and reaction byproducts

Operating Cost Calculations

Utilization Rate	78%	Annual Oper	ating Hours	5,774			
	Unit	Unit of	Use	Unit of	Annual	Annual	Comments
Item	Cost \$	Measure	Rate	Measure	Use*	Cost	
Operating Labor							
Op Labor	60.00	\$/Hr	2.0 h	nr/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 h	nr/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, Replaceme	ents & Wast	e Management					
Electricity	0.076	\$/kwh	252.1 k	:W-hr	1,455,398	\$ 110,610	\$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization
Water			N/A g	j pm			
Compressed Air	0.467	\$/kscf	2.0 s	cfm/kacfm	125,438	\$ 58,624	\$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization
Cooling Water			N/A g	,pm			
Solid Waste Disposal	41.32	\$/ton	0.6 to	on/hr	2,716	\$ 112,208	\$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization
Trona	285.00	\$/ton	1,501.1 lk	o/hr	3,380	\$ 963,375	\$/ton, 1,501.1 lb/hr, 5774 hr/yr, 78% utilization
Filter Bags	249.27	\$/bag	3,412 b	bags	N/A	\$ 225,950	\$/bag, 3,412 bags, 5774 hr/yr, 78% utilization

DSI Summary

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 devic	e cost (A)					27,416,821
Installation - Standard Costs	74%	of purchased e	quip 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 e	quip 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, supervis	abor, supervision, materials, replacement parts, utilities, etc.					1,140,905
Total Annual Indirect Operating Costs		Sum indirect op	Sum indirect oper costs + capital recovery cost					9,080,966
Total Annual Cost (Annualized Capital Co	ost + 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.

SDA Summary

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 + p	acking + 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	-
		N10
I otal Site Specific Costs		NA 20 299 447
Installation Total		20,200,447
I otal Direct Capital Cost, DC		47,705,200
	10% of purchased equip cost (B)	2 7/1 682
Construction & field expanses	10% of purchased equip cost (B)	Z,741,002 E 492.264
Contractor fees	10% of purchased equip cost (B)	5,465,304 2 741 682
Start-up	1% of purchased equip cost (B)	2,741,002
Performance test	1% of purchased equip cost (B)	274,100
Model Studies	N/A of purchased equip cost (B)	274,100
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		61 062 015
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		40.005
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
Electricity	109 \$/laub 420.1 1/1/ br 5774 br//rr 700/ utilization	101 250
Compressed Air	0.00 p/KWII, 420.1 KVV-III, 3774 III/YI, 78% UllilZallOI 0.47 \$/keef 2.0 cefm/keefm 5774 br/vr 78% utilization	104,350
N/A	0.47 g/rsci, 2.0 sciiii/raciiii, 3774 iii/yi, 70% uuii2auon	- 50,024
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		-
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	Нр	kW	
Blower, Baghouse	232,100	10.00	-	·	2,425,663	Electricity demand for new baghouse
Total					2,425,663	
Reagents and Other Oper	rating 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 se	orbent and reaction byproducts
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Operating Cost Calculations

Util	ization Rate	78%	Annual Ope	rating Hours	5,774			
		Unit	Unit of	Use	Unit of	Annual	Annual	Comments
ltem		Cost \$	Measure	Rate	Measure	Use*	 Cost	
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 Maintena	nce Labor		NA	\$ 43,305	100% of Maintenance Labor
Utilities, Supplies, F	Replacements	s & Waste N	lanagement					
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

SDA Summary

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?	What type of fuel does the unit burn?
Is the SNCR for a new boiler or retrofit of an existing boiler?	
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.	
Complete all of the highlighted data fields:	
	Provide the following information for coal-fired boilers:
What is the maximum heat input rate (QB)? 430 MMBtu/hour	Type of coal burned:
What is the higher heating value (HHV) of the fuel? 4,597 Btu/lb	Enter the sulfur content (%S) = 0.05 percent by weight
	Select the appropriate SO ₂ emission rate:
What is the estimated actual annual fuel consumption? 517,045,435 lbs/Year	
Is the boiler a fluid-bed boiler?	Ash content (%Ash): 2.8 percent by weight
	For units burning coal blends:
Enter the net plant heat input rate (NPHR)	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
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	Fraction in Coal Blend%S%AshHHV (Btu/lb)Fuel Cost (\$/MMBtu)Bituminous01.849.2311,8412.4Sub-Bituminous00.415.848,8261.89Lignite00.8213.66,6261.74Please 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	Plant Elevation	1083 Feet above sea
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			
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	Densities of typical S	NCR reagents:
Number of days reagent is stored (t _{storage})	14	days	50% urea so	olution 71 lb
Estimated equipment life	20	Years	29.4% aqueo	us NH ₃ 56 lb
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	CEPCI = Chemical Engineering F
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*	

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.

level

os/ft³ os/ft³

Plant Cost Index

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used you used and the re
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 U.S. Geological https://pubs.us \$/gallon price v (510 \$/ton NH3 SOL / ft3 SOL) /
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 Info for MN industri https://www.e pmt 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 Info Table 7.4. Publi https://www.e
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 listed under 'ba https://www.fe

r own site-specific values, please enter the value eference source...

of 29% Ammonia)

Survey, Minerals Commodity Summaries, 2021 gs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. vas back calculated.

8) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb / (7.48052 gal SOL / ft3 SOL) = \$0.554/gallon of 29%

ormation Administration. Electric Power, January 2022 al users. Available at: ia.gov/electricity/monthly/epm_table_grapher.php?t=e

)

ormation Administration. Electric Power Annual 2020. shed March 2022. Available at: ia.gov/electricity/annual/pdf/epa.pdf.

e is as of March 2, 2021 and is available as the rates ink prime loan' at ederalreserve.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 =	$NOx_{in} \times EF \times Q_B =$	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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOX} \times SR) =$	141	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
Reagent Usage Rate (m _{sol}) =	$m_{reagent}/C_{sol} =$	485	lb/hour
	(m _{sol} x 7.4805)/Reagent Density =	64.8	gal/hour
Estimated tank volume for reagent storage =	(m _{sol} x 7.4805 x t _{storage} x 24 hours/day)/Reagent	21.900	gallons (storage needed to store a 14 day reagent supply
	Density =	21,800	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx _{in} x NSR x 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 x m _{reagent} x ((1/C _{inj})-1) =	1.14	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1x10 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:	
	$TCI = 1.3 x (SNCR_{cost} + BOP_{cost})$
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

\$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.

Balance of Plant Costs (BOP_{cost}) =

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 x (0.1 x Q_B x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF		
For Fuel Oil and Natural Gas-Fired Industrial Boilers:		
$SNCR = 147000\mathrm{x}((\Omega_{-}/\mathrm{NPHR})\mathrm{x}\mathrm{HRE})^{0.42}\mathrm{x}\mathrm{FLEVE}\mathrm{x}\mathrm{RE}$		
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:		
$APH_{res} = 69,000 \times (0.1 \times O_{p} \times HRE \times CoalE)^{0.78} \times AHE \times RE$		
Air Pre-Heater Costs (APH) = \$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:		
$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_{x}Removed/hr)^{0.12} \times BTF \times RF$		
For Fuel Oil and Natural Gas-Fired Utility Boilers:		
$BOP_{cost} = 213.000 \times (B_{MW})^{0.33} \times (NO_{v}Removed/hr)^{0.12} \times RF$		
For Coal-Fired Industrial Boilers:		
BOP = $320000 \times (0.1 \times \Omega_{-})^{0.33} \times (NO \text{ Removed/br})^{0.12} \times \text{BTE x BE}$		
For Fuel Oil and Natural Gas-Fired Industrial Boilers:		
$POP = -312000 \text{ w} (0.400 \text{ MPLP})^{0.33} \text{ w} (NO \text{ Permaved}/ha)^{0.12} \text{ w} \text{ PC}$		
$BOP_{cost} = 213,000 \times (Q_B/NPRK) \times (NO_x Removed/nr) \times RF$		
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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$198,159 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$8,328 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$2,544 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$11,960 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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?	lustrial	What type of fuel does the unit burn?		
Please enter a retrofit factor between 0.8 and 1.5 based on the level of o projects of average retrofit difficulty.	difficulty. Enter 1 for 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	Provide the following information for coal-fired boilers: Type of coal burned: Lignite		
What is the higher heating value (HHV) of the fuel?	4,597 Btu/lb	Enter the sulfur content (%S) = 0.05 percent by weight		
What is the estimated actual annual fuel consumption?	517,045,435 lbs/Year			
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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.		
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW	Coal TypeCoal Blend%SHHV (Btu/lb)Bituminous01.8411,841Sub-Bituminous00.418,826Lignite00.826,685		
Plant Elevation	1083 Feet above sea level	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:		

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t _{SCR})	352 days		Number of SCR reactor chambers (n_s	_{cr})	1
Number of days the boiler operates (t _{plant})	352 days		Number of catalyst layers (R _{layer})		3
Inlet NO _x Emissions (NOx _{in}) to SCR	0.292 lb/MMBtu		Number of empty catalyst layers (R _{en}	_{npty})	1
Outlet NO _x Emissions (NOx _{out}) from SCR	0.058 lb/MMBtu	80.0% Assumed Control	Ammonia Slip (Slip) provided by vend	dor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	emelency	Volume of the catalyst layers (Vol _{catal} (Enter "UNK" if value is not known)	_{lyst})	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.			Flue gas flow rate (Q _{fluegas}) (Enter "UNK" if value is not known)		UNK acfm
		1			
Estimated operating life of the catalyst (H _{catalyst})	20,000 hours			_	
Estimated SCR equipment life	25 Years*		Gas temperature at the SCR inlet (T)		413 °F
* For industrial boilers, the typical equipment life is between 20 and 25 years.		_	Base case fuel gas volumetric flow ra	te factor (Q _{fuel})	547 ft ³ /min-MMBtu/hour
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of	29% and density of 56 lbs/cft are default		
Density of reagent as stored (ρ_{stored})	56 Ib/cubic feet*	values for ammonia reagent. U	ser should enter actual values for reagent, if		
Number of days reagent is stored (t _{storage})	14 days			Densities of typical	SCR reagents:
				50% urea solution 29.4% aqueous NH	71 lbs/ft ³ 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 = Chemica
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	-
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing catalyst	* \$227/cf is a defau
Catalyst cost (CC _{replace})	227.00	and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a def
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a

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.

cal Engineering Plant Cost Index

ault value for the catalyst cost based on 2016 prices. User should enter actual value,

fault value for the operator labor rate. User should enter actual value, if known.

default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source . . .

(\$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 / ft2 SOL) / (7 48052 gol SOL / ft2 SOL) = \$0 554 (gollon of 20%) (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

(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 =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	277.62	tons/year
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 x [(59-(0.00356xh)+459.7)/518.6] ^{5.256} x (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.

347.02125

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 _{astalyst}) =			
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	(A) 10.5	14.6	foot
reactor =	(A _{SCR})	14.0	leet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	79	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent
		-

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

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	247.91	kW
	where $A = (0.1 \times QB)$ for industrial boilers.		

Density =

t (MW) = 17.03 g/mole 56 lb/ft³

14 day reagent supply rounded to t

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:	0.2 0.92	
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (0.1 \text{ x} Q_B \text{ x} \text{ CoalF})^{0.52} \text{ x} \text{ ELEVF x RF}$	
SCR Capital Costs (SCR _{cost}) =		\$16,277,179 in 2019 dollars
	Reagent Preparation Costs (RPC)	
For Coal-Fired Utility Boilers >25 MW:	0.25	
	$RPC = 564,000 \text{ x } (NOx_{in} \text{ x } B_{MW} \text{ x } NPHR \text{ x } EF)^{0.23} \text{ x } RF$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.23} \times RF$	
Reagent Preparation Costs (RPC) =		\$2,663,198 in 2019 dollars
For Coal Fired Utility Boilers >25MW:	Air Pre-Heater Costs (APHC)*	
For Coal-Fired Ounty Bollers >2510100.	$\Delta PHC = 69,000 \times (B_{\text{even}} \times HBE \times CoalE)^{0.78} \times \Delta HE \times BE$	
For Coal-Fired Industrial Boilers >250 MMBtu/bour:	$AFTIC = 05,000 \times (B_{MW} \times TINE \times COall) \times AFTI \times NI$	
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH _{cost}) =		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers that	at 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 x $(B_{MW} x HRFx CoalF)^{0.42} x ELEVF x RF$

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

BPC = 529,000 x $(0.1 \times Q_B \times CoalF)^{0.42}$ ELEVF x 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 meth	ods may be used to calcuate the catalyst replacement cost.	* Colouistics Mathed 1 colocted
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): $(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
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?
Is the SNCR for a new boiler or retrofit of an existing boiler?	ofit 💌		
Please enter a retrofit factor equal to or greater than 0.84 based of difficulty. Enter 1 for projects of average retrofit difficulty.	n the level of	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:			Provide the following information for coal-fired boilers:
What is the maximum heat input rate (QB)?	472.4	MMBtu/hour	Type of coal burned: Sub-Bituminous
What is the higher heating value (HHV) of the fuel?	8,999	Btu/lb	Enter the sulfur content (%S) = 0.28 percent by wei
What is the estimated actual annual fuel consumption?	342,550,000	lbs/Year	Or Select the appropriate SO ₂ emission rate: Not Applicable
Is the boiler a fluid-bed boiler?	No 🔻		*The ash content of 5.84% is a default value. See below for data source. F
			For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW	Note: The table below is pre-populated with default values enter the actual values for these parameters in the table be parameter is not known, you may use the default values pro
			Fraction in Coal Blend
If the NPHR is not known, use the default NPHR value:	Fuel Type Coal Fuel Oil	Default NPHR 10 MMBtu/MW 11 MMBtu/MW	Bituminous0Sub-Bituminous0Lignite0
	Natural Gas	8.2 MINIBTU/MW	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	4 days	Plant Elevation	1100 Feet above sea
Number of days the boiler operates (t _{plant})	314	4 days		
Inlet NO _x Emissions (NOx _{in}) to SNCR	0.5	b/MMBtu		
Oulet NO _x Emissions (NOx _{out}) from SNCR	0.3	<mark>3</mark> lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	1.5	7	*The NSR for a urea system may be calculat Control Cost Manual (as updated April 2019	ted using equation 1.17 in Sectio)).
Concentration of reagent as stored (C _{stored})	50	<mark>)</mark> Percent]	
Density of reagent as stored ($ ho_{stored}$)	7:	1 lb/ft ³		
Concentration of reagent injected (C _{inj})	10	<mark>0</mark> percent	Densities of typical S	NCR reagents:
Number of days reagent is stored (t _{storage})	14	<mark>4</mark> days	50% urea se	olution 71 lb
Estimated equipment life	20) Years	29.4% aqueo	ous NH ₃ 56 lb
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	CEPCI = Chemical Engineering P
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*	

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) = Administrative Charges Factor (ACF) = 0.015 0.03

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ion 4, Chapter 1 of the Air Pollution



Plant Cost Index

Data Sources for Default Values Used in Calculations:

			lf vou used vou
Data Element	Default Value	Sources for Default Value	used and the re
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 Info for MN industri https://www.ei pmt 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 listed under 'ba https://www.fe

r own site-specific values, please enter the value eference source...

ormation Administration. Electric Power, January 2022 ial users. Available at: ia.gov/electricity/monthly/epm_table_grapher.php?t=e

te is as of March 2, 2021 and is available as the rates ank prime loan' at ederalreserve.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
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	

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* 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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOX} \times SR) =$	285	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
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	20,200	gallons (storage needed to store a 14 day reagent supply
	Density =	20,200	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

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) =	(Δ fuel 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} = 22	20,000 x (B _{MW} x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF
For Fuel Oil and Natural Gas-Fired Utility Boilers:	
SNCR	$x_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers:	
SNCR _{cost} = 220	,000 x (0.1 x Q _B x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF
For Fuel Oil and Natural Gas-Fired Industrial Boile	ers:
SNCR _{cost}	= 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x 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 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF
For Coal-Fired Industrial Boilers:	
APH _{cost} =	69,000 x (0.1 x Q _B x HRF x CoalF) ^{0.78} x AHF x RF
Air Pre-Heater Costs (APH _{cost}) =	\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boild sulfur dioxide.	ers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of
	Relance of Plant Costs (ROP)
For Coal-Fired Litility Boilers:	Datatice of Flatt Costs (BOF _{cost})
$B \cap P = 320$	$0.000 \times (B_{\rm em})^{0.33} \times (NO \text{ Removed/br})^{0.12} \times BTE \times BE$
For Fuel Oil and Natural Gas-Fired Utility Boilers:	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,
BOP =	213,000 x $(B_{\rm resc})^{0.33}$ x (NO Removed/br) ^{0.12} x BE
For Coal-Fired Industrial Boilers:	
BOP = 320.0	$(0.1 \times O_{\rm p})^{0.33} \times (NO_{\rm r}Removed/hr)^{0.12} \times BTE \times RE$
For Fuel Oil and Natural Gas-Fired Industrial Boile	ers:
$BOP_{cost} = 21$	$3,000 \times (Q_{\rm B}/{\rm NPHR})^{0.33} \times ({\rm NO_{v}Removed/hr})^{0.12} \times {\rm RF}$
· cost	
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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$649,903 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$11,292 in 2019 dollars
Annual Water Cost =	$q_{water} x Cost_{water} x t_{op} =$	\$7,427 in 2019 dollars
Additional Fuel Cost =	Δ Fuel x Cost _{fuel} x t _{op} =	\$28,444 in 2019 dollars
Additional Ash Cost =	$\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$	\$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?	ustrial 🔻	What type of fuel does the unit burn?
Please enter a retrofit factor between 0.8 and 1.5 based on the level of c projects of average retrofit difficulty.	lifficulty. Enter 1 for 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	Provide the following information for coal-fired boilers: Type of coal burned: Sub-Bituminous
What is the higher heating value (HHV) of the fuel?	8,999 Btu/lb	Enter the sulfur content (%S) = 0.28 percent by weight
What is the estimated actual annual fuel consumption?	342,550,000 lbs/Year	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
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	Fraction in
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW	Coal TypeCoal Blend%SHHV (Btu/lb)Bituminous01.8411,841Sub-Bituminous00.418,826Lignite00.826,685
Plant Elevation		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 2 Not applicable



Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	314 days	Number of SCR reactor chambers (n _{scr})	1
Number of days the boiler operates (t _{plant})	314 days	Number of catalyst layers (R _{layer})	3
Inlet NO _x Emissions (NOx _{in}) to SCR	0.59 lb/MMBtu	Number of empty catalyst layers (R _{empty})	1
Outlet NO _x Emissions (NOx _{out}) from SCR	0.05 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	0.525	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*	Gas temperature at the SCR inlet (T)	650 °F
* For industrial boilers, the typical equipment life is between 20 and 25 years.		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*	*The reagent concentration of 50% and density of 71 lbs/cft are default	
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*	values for urea reagent. User should enter actual values for reagent, if different from the default values provided	
Number of days reagent is stored (t _{storage})	14 days	<u>Densities of typic</u> 50% urea solutio 29.4% aqueous N	n 71 lbs/ft ³ IH 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
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	1.660	¢/gallon for 50% urea*	* \$1.66/gallon is a de
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a default
Catalyst cost (CC _{replace})	227.00	catalyst and installation of new catalyst	if known.
Operator Labor Rate	67.53	\$/hour (including benefits)	
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a de

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.

I Engineering Plant Cost Index

efault value for 50% urea. User should enter actual value, if known.

t value for the catalyst cost based on 2016 prices. User should enter actual value,

efault value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	
Reagent Cost (\$/gallon)	Sources for Default Value \$1.66/gallon 50% U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector urea solution 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-		
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.	(
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	([

f you used your own site-specific values, please enter the value used and the reference source ...

(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

(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 =	$NOx_{in} x EF x Q_B =$	254.99	lb/hour
Total NO _x removed per year =	(NOx _{in} x EF x Q _B x 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 x [(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.

909
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}) =			
, 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	()0.5	15.0	foot
reactor =	(A _{SCR})	15.0	leet
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) =

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

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	270.15	kW
	where $A = (0.1 \times QB)$ for industrial boilers.		

Density =

60.06 g/mole 71 lb/ft³

14 day reagent supply rounded to t

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers		
For Coal-Fired Boilers:		
	TCI = 1.3 x (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 red 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:		
SC	$CR_{cost} = 310,000 \text{ x (NRF)}^{0.2} \text{ x (B}_{MW} \text{ x HRF x CoalF)}^{0.92} \text{ x ELEVF x RF}$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
S	SCR _{cost} = 310,000 x (NRF) ^{0.2} x (0.1 x Q _B x CoalF) ^{0.92} x ELEVF x RF	
		620 221 222 in 2010 dollars
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 x (NOx _{in} x B _{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NO x_{in} x Q_B x EF) ^{0.25} x 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 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x RF	
		44.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4
Air Pre-Heater Costs (APH _{cost}) =		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers that bur	rn 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 x (B_{MW} x HRFx CoalF) x ELEVF x RF

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

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

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):	$(Q_{B}/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
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: NOx 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 dev	vice cost (A)				774,294
Installation - Standard Costs	30%	of purchasec	l 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		<u> </u>	<u> </u>				
Total Annual Direct Operating Costs		Labor, super	vision, materials	s, replacement	t parts, utilitie	s, etc.	1,145,260
Total Annual Indirect Operating Costs		Sum indirect	oper costs + ca	pital recovery	cost		268,953
Total Annual Cost (Annualized Capital Co	st + Operatin	ig Cost)					1,414,213

Notes & Assumptions

Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
 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 + pac	cking + auxiliary equipment, EC	00 500
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 Propagation, as required		ΝΔ
Sile Fleparation, as required	Site Specific	
Site Specific - Other	Site Specific	NA NA
Total Site Specific Costs	Site Specific	NA
Installation Total	—	232.288
Total Direct Capital Cost, DC		1,006,582
Indirect Conitel Costs		
Engineering supervision	10% of purchased equip cost (B)	77 120
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 B	ags, etc) for Capital Recovery Cost	1,300,814
Total Capital Investment (TCI) with Retrofit Factor	50%	1,951,221
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		28,307
Flectricity	0 08 \$/kwh 774 kW-hr 6525 28365701702 hr/vr 100% utilization	402 205
Natural Gas	3 90 \$/mscf 428 scfm 6525 28365791702 hr/yr 100% utilization	-02,200 653 600
		000,000

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 Fact	ors]			
Primary Installation		• • • • • • • • • • • • • • • • • •				
Interest Rate		3.50%				
Equipment Life		20 years				
CRF		0.0704	J			
Replacement Catalyst	: C	atalyst				
Equipment Life		3 years				
CRF		0.3569				
Rep part cost per unit		0 \$/ft ³				
Amount Required		39 ft ³				
Catalyst Cost		0 Cost adjuste	d for freight &	sales tax		
Installation Labor		0 Assume Lab	or = 15% of ca	talyst cost (b	basis labor fo	or baghouse replacement)
Total Installed Cost		0 Zero out if	no replacemer	nt parts nee	ded	
Annualized Cost		0	-	-		
Replacement Parts & I	Equipment:					
Equipment Life		3				
CRF		0.3569				
Rep part cost per unit		0 \$ each				
Amount Required		0 Number				
Total Rep Parts Cost		0 Cost adjuste	d for freight &	sales tax		
Installation Labor		0 10 min per b	ag (13 hr total)	Labor at \$2	9.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost		0 Zero out if	no replacemer	it parts nee	ded	
Annualized Cost		0				
Electrical Use						
	Flow acfm	ΔP in H2O	Efficiency	Нр	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)

Reagent Use & Other Operating Costs	Oxidizers - NA		
Operating Cost Calculations	Annual hours of operation:	6,525	
	Utilization Rate:	100%	

774.3

		offization Rate.			10070		
ltem	Unit Cost \$	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	69.56	\$/Hr	0.5	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	5 hr/8 hr shift	408	28,367	\$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr
Maint Mtls	100	% of Maintena	ince Labor		NA	28,367	100% of Maintenance Labor
Utilities, Supplies, Repla	acements &	Waste Manag	gement				
Electricity	0.080	\$/kwh	774.3	8 kW-hr	5,052,821	402,205	\$/kwh, 774 kW-hr, 6525.28365791702 hr/yr, 100% utilization
Natural Gas	3.90	\$/mscf	428	3 scfm	167,615	653,699	\$/mscf, 428 scfm, 6525.28365791702 hr/yr, 100% utilization

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

A								
Auxiliary Fuel Use	Equation 3.19)			_			
T _{wi}	370	Deg F - Te	emperature	of waste gas int	to 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 F	leat Recove	ery % Heat reco	overy section efficier	псу		
T _{wo}	566	Deg F - Te	emperature	of waste gas ou	t of heat recovery			
T _{fo}	454	Deg F - Te	emperature	of flue gas out o	of heat recovery			
-h _{caf}	21502	Btu/lb Hea	t of combu	stion auxiliary fu	uel (methane)			
-h _{wa}	0	0 Btu/lb Heat of combustion waste gas						
C _{p wg}	0.2684	Btu/lb - De	g F Heat C	apacity of waste	e gas (air)			
p_{wg}	0.0739	b/scf - De	nsity of wa	ste gas (air) at 7	7 Deg F			
p_{af}	0.0408	b/scf - De	nsity of aux	iliary fuel (meth	ane) at 77 Deg F			
Q _{wg}	132,954 :	scfm - Flov	v of waste	jas				
Q _{af}	428	scfm - Flov	v of auxiliar	y fuel				
Year	2005	Inf	lation Rate	3.0%				
Cost Calculations		133,382	scfm Flue	Gas	Cost in 1989 \$'s	\$407,859		
	-		Current	Cost Using CHE	E Plant Cost Index	\$635,318		
	Heat Rec %	А	В					
	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			

mw CO	100 scfm Gas Composition 0 v %	359 lb/hr f	scf/lbmole wt %	Cp Gas	Cp Flue
mw CO	Gas Composition 0 v %	اb/hr f	wt %	Cp Gas	Cp Flue
mw CO	0 v %	0			-
		0			·
mw CO2	15 v %	184	22.0%	0.24	0.0528
mw H2O	10 v %	50	6.0%	0.46	0.0276
mw N2	60 v %	468	56.0%	0.27	0.1512
mw O2	15 v %	134	16.0%	0.23	0.0368
p Flue Gas	100 v %	836	100.0%		0.2684
י ני יי רי	mw N2 mw O2 Flue Gas	mw N2 60 v % mw O2 15 v % o Flue Gas 100 v %	mw N2 60 v % 468 mw O2 15 v % 134 o Flue Gas 100 v % 836	mw N2 60 v % 468 56.0% mw O2 15 v % 134 16.0% o Flue Gas 100 v % 836 100.0%	mw N2 60 v % 468 56.0% 0.40 mw O2 15 v % 134 16.0% 0.23 o Flue Gas 100 v % 836 100.0%

(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 co	ost (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, repla	acement parts	, utilities, etc.		89,357
Total Annual Indirect Operating Costs		Sum indirect oper of	costs + capital r	ecovery cost			643,095
Total Annual Cost (Annualized Capital Cos	st + Operating	g Cost)					732,452

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Cont. Emis. Ib/hr	Cont. Emis. Ib/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

Purchased equipment and installation costs from vendor
 Assumed 0.5 hr/shift operatior and maintenance labor for LNB
 Controlled emission factor based on vendor estimated burner/OFA performance

X:\Programs\Air_Quality_Programs\Regional Haze\2021 RH SIP (Round 2)\MN Four Factor Analysis\Southern Minnesota Beet Sugar Coop\MPCA FFA Costs (Southern MN Beet Sugar) (2022-06-09). x7/3/26/2022 LNB-OFA Summary Page 5 of 7

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 + pa	acking + 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
Flectrical	0% of purchased equip cost (B)	0
Dining	0% of purchased equip cost (B)	0
	0% of purchased equip cost (B)	0
Painting	0% of purchased equip cost (B)	0
Failung		1 215 000
Installation Subtotal Standard Expenses	0%	1,215,900
Installation Total		1 215 900
Total Direct Capital Cost, DC		2,758,680
Indiract 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 / 28
Performance test	1% of purchased equip cost (B)	15,420
Model Studies	NA of purchased equip cost (B)	13,420 ΝΔ
Contingongios	10% of purchased equip cost (D)	15/ 270
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 B	ags, 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 Mana	agement	
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 + Opera	ting Cost)	732,452

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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 & Ot	ther Operating Co	sts						
	-							
Operating Cost Ca	alculations		Annual ho	urs of operatio	on:	6,52	;	
			Utilization	Rate:		1009	, D	
ltem	Unit Cost [©]	Unit of	Use Rate	Unit of	Annual	Annual Cost	Comments	

ltem

69.56 \$/Hr	0.5 hr/8 hr shift	408	28,367 \$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr
15% of Op.		NA	4,255 15% of Operator Costs
69.56 \$/Hr	0.5 hr/8 hr shift	408	28,367 \$/Hr, 0.5 hr/8 hr shift, 6525.28365791702 hr/yr
100 % of Maintena	nce Labor	NA	28,367 100% of Maintenance Labor
ements & Waste Manage	ement		
0.080 \$/kwh	0.0 kW-hr	0	0 \$/kwh, 0 kW-hr, 6525.28365791702 hr/yr, 100% utilization
3.90 \$/kscf	0 scfm	0	0 \$/kscf, 0 scfm, 6525.28365791702 hr/yr, 100% utilization
5.28 \$/kgal	0.0 gpm	0	0 \$/kgal, 0 gpm, 6525.28365791702 hr/yr, 100% utilization
	69.56 \$/Hr 15% of Op. 69.56 \$/Hr 100 % of Maintenau ements & Waste Manage 0.080 \$/kwh 3.90 \$/kscf 5.28 \$/kgal	69.56 \$/Hr 0.5 hr/8 hr shift 15% of Op. 69.56 \$/Hr 0.5 hr/8 hr shift 100 % of Maintenance Labor 69.56 \$/Hr 0.5 hr/8 hr shift 100 % of Maintenance Labor 69.56 \$/Hr 0.5 hr/8 hr shift 0.080 \$/kwh 0.0 kW-hr 3.90 \$/kscf 0 scfm 3.90 \$/kgal 0.0 gpm 5.28 \$/kgal 0.0 gpm	69.56 \$/Hr 0.5 hr/8 hr shift 408 NA 69.56 \$/Hr 0.5 hr/8 hr shift 408 NA 69.56 \$/Hr 0.5 hr/8 hr shift 408 NA 100 % of Maintenance Labor NA ements & Waste Management 0.00 kW-hr 0 0.080 \$/kwh 0.0 kW-hr 0 3.90 \$/kscf 0 scfm 0 5.28 \$/kgal 0.0 gpm 0

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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)

Boiler 1

Operating Unit:

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
Purchased Equipment Total (B)	22%	of control device	e cost (A)					16
Installation - Standard Costs	74%	of purchased ec	quip cost (B)					12
Installation - Site Specific Costs								
Installation Total								12
Total Direct Capital Cost, DC								28
Total Indirect Capital Costs, IC	52%	of purchased ec	quip cost (B)					8
Total Capital Investment (TCI) = DC + IC								36
Adjusted TCI for Replacment Parts								36
TCI with Retrofit Factor								54
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					6	
Total Annual Cost (Annualized Capital Cos	st + Operating Co	ost)						7

Emission Control Cost Calculation

	Max Emis	Annual	Cont Eff	Exit	Conc.	Cont Emis	Reduction	Cont
Pollutant	Lb/Hr	T/Yr	%	Conc.	Units	T/yr	T/yr	\$/Ton
PM10						0.0	-	
PM2.5						0.0	-	
Total Particulates						0.0	-	
Nitrous Oxides (NOx)						0.0	-	
Sulfur Dioxide (SO ₂)		795.0	90%			79.5	715.5	
Sulfuric Acid Mist						0.00	-	
Fluorides						0.0	-	
Volatile Organic Compounds (VOC)						0.0	-	
Carbon Monoxide (CO)						0.0	-	
Lead (Pb)						0.00	-	

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



ost				
Rem				
NA				
10,097				
NA				

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 + pa	acking + auxiliary equipment, EC	4 000 440
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)		
	N/A pite presifie	
Site Preparation, as required		-
Site Specific - Other	N/A Site Specific	-
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)	
Contingoncios	10% of purchased equip cost (B)	1 629 796
Total Indirect Canital Costs IC	52% of purchased equip cost (B)	8 469 688
		-,,
Adjusted TCI for Replacement Parts (Catalyst, Filter	Bags, etc) for Capital Recovery Cost	36,810,567 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 Mar	nagement	
Electricity	0.08 \$/kwh, 436.9 kW-hr, 6525.28365791702 hr/yr, 100% utilization	226,923
Compressed Air N/A	0.50 \$/kscf, 2.0 scfm/kacfm, 6525.28365791702 hr/yr, 100% utilizat	81,142 -
15% of Operator Costs	65.24 \$/top 0.2 top/br 6525 28365701702 br/vr 100% utilization	102 545
	180.10 \$/ton, 0.2 loh/hr, 6525.28365791702 hr/yr, 100% utilization	201 154
0 \$/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		-
		-
IN/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)	545 200
Insurance (1% total capital costs)	1% of total capital costs (TCI)	545 200
Canital Recovery	0 0704 for a 20- year equinment life and a 3.5% interest rate	2 928 750
Total Annual Indirect Operating Costs	Sum indirect oper costs + canital recovery cost	6.265 971
		0,200,071
Total Annual Cost (Annualized Canital Cost + Operat	ing Cost)	7 224 301

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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%	, 0				
Equipment Life	20) years				
CRF	0.0704	1				
Replacement Parts & Equipment:	Filter Bags					
Equipment Life	Ę	5 years				
CRF	0.2215	5				
Rep part cost per unit	234.86	6 \$/bag				
Amount Required	1620)				
Total Rep Parts Cost	425,718	3 Cost adjuste	d for freight & sal	les tax		
Installation Labor 37,560 20 min per bag					EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.	
Total Installed Cost	463,278	3 Zero out if r	no replacement	parts neede	ed	lists replacement times from 5 - 20 min per bag.
Annualized Cost	102,608	3				
Electrical Use						
Flow	acfm	D P in H2O	Efficiency	Нр	kW	
Plower Perhause 200	000	10.00			2 950 702	Incremental electricity increase over with baghouse repla
Blower, Baghouse 208	1,000	10.00			2,000,793	scrubber including ducting
Total					2,850,793	
Reagents and Other Operating Costs						
Lime Lice Pate		lh mala SO2	202 17	lb/br Limo		
		ID-11018 302	202.17			
Solid Waste Disposal	1,572 ton/yr unreac	ted sorbent an	d reaction byproc	lucts		
<u>[</u>						

Operating Cost Calculations

Utilization Rate	100%	Annual Ope	erating Hours	6,525			
	Unit	Unit of	Use	Unit of	Annual	Annual	Comments
ltem	Cost \$	Measure	Rate	Measure	Use*	Cost	
Operating Labor							
Op Labor	69.56	5 \$/Hr	2.0	hr/8 hr shift	1,631	\$ 113,469	\$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr
Supervisor	15%	o of Op.			NA	\$ 17,020	15% of Operator Costs
Maintenance							
Maint Labor	69.56	5 \$/Hr	1.0 I	hr/8 hr shift	816	\$ 56,734	\$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr
Maint Mtls	100	% of Maintena	nce Labor		NA	\$ 56,734	100% of Maintenance Labor
Utilities, Supplies, Replacements	s & Waste M	anagement					
Electricity	0.080) \$/kwh	436.9 I	kW-hr	2,850,793	\$ 226,923	\$/kwh, 436.9 kW-hr, 6525.28365791702 hr/yr, 100% utili
Compressed Air	0.496	5 \$/kscf	2 :	scfm/kacfm	163,654	\$ 81,142	\$/kscf, 2.0 scfm/kacfm, 6525.28365791702 hr/yr, 100% i
\$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr	5.282	2 \$/mgal	9	gpm			\$/mgal, 0 gpm, 6525.28365791702 hr/yr, 100% utilization
15% of Operator Costs	65.24	\$/ton	0.24 1	ton/hr	1,572	\$ 102,545	\$/ton, 0.2 ton/hr, 6525.28365791702 hr/yr, 100% utilization
	189.19) \$/ton	282.2	b/hr	1,063	\$ 201,154	\$/ton, 282.2 lb/hr, 6525.28365791702 hr/yr, 100% utilizat
\$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr	234.86	s \$/bag	1,620 I	bags	N/A	\$ 102,608	\$/bag, 1,620 bags, 6525.28365791702 hr/yr, 100% utiliza
100% of Maintenance Labor							



acing

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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 of	cost (A)			11,342,240
Installation - Standard Costs	74%	of purchased equi	p 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 equi	p 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, supervisior	n, materials, replac	ement parts, utilitie	s, etc.	1,870,007
Total Annual Indirect Operating Costs		Sum indirect oper	costs + capital rec	covery cost		4,415,695
Total Annual Cost (Annualized Capital Cos	t + Operating Co	ost)				6,285,702

Emission Control Cost Calculation

	Max Emis	Annual	Cont Eff	Cont Emis	Reduction	Cont Cost
Pollutant	Lb/Hr	Ton/Yr	%	Ton/Yr	Ton/Yr	\$/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

Costs scaled up to design airflow using the 6/10 power law
 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
 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 Sys	stem + 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	1% of nurchased equin cost (B)	453 600
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)	-	
	N/A Site Specific	
Site Preparation, as required		
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 Adjusted TCI for Replacement Parts (Catalyst, Filter	- Bags, etc) for Capital Recovery Cost	25,633,463 25,170,184
Total Capital Investment (TCI) with Retrofit Factor	50%	37,755,277
OPERATING COSTS		
Direct Annual Operating Costs, DC		
		112 460
Supervisor	$\begin{array}{c} 0.15 \text{of } \Omega_{\text{D}} \mid \\ 0.15 \text{of } \Omega_{\text{D}} \mid \text{obs} \end{array}$	17.020
Maintenance	0.15 01 Op Labor	17,020
Maintenance Labor	60 56 \$/Hr	56 734
Maintenance Materials	100 % of Maintenance Labor	56,734
Utilities, Supplies, Replacements & Waste Ma	inagement	
Electricity	0.08 \$/kwh, 262.1 kW-hr, 6525.28365791702 hr/yr, 100% utilizatio	136,154
N/A		-
Compressed Air	0.50 \$/kscf, 2.0 scfm/kacfm, 6525.28365791702 hr/yr, 100% utiliz	81,142
N/A Solid Wasta Dispasal	65.24 \$/ton 0.5 ton/br 6525.28265701702 br/vr 100% utilization	-
Trona	285 00 \$/ton, 0.5 toll/lll, 0525.26505791702 lll/yl, 100% utilization	220,001
Filter Bags	234 86 \$/hag 1 620 bags 6525 28365791702 hr/yr 100% utilization	102 608
N/A	234.00 \$\bag\$, 1,020 bag\$, 0525.20505731702 11/y1, 100% utilization	102,000
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
		0.005 700
Total Annual Cost (Annualized Conital Cost + Original		

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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	S			
Primary Installation				
Interest Rate		3.50%		
Equipment Life		20 years		
CRF		0.0704		
Replacement Parts & Eq	uipment: Filte	er 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 fre	ight, sales tax, and bag disposal	
Installation Labor		37,560 20 min per bag		
Total Installed Cost		463,278		
Annualized Cost		102,608		
Electrical Use		D D := 1/20	1.10/Jac. /	
	Flow actm	D P In H2O	KVVNI/yr	Incremental electricity increases over with beckeyee
Blower	209,000	6.00	1,710,476	scrubber including ducting
Total			1,710,476	
Reagent Use & Other Op	erating Costs			
Trona use - 1.5 NSR	243.67 lb/h	r SO2 1158.62 lb/hr Tr	ona	
Solid Waste Disposal	3,507 ton/	yr DSI unreacted sorbent and re	eaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Ope	erating Hours	6,525			
	Unit	Unit of	Use	Unit of	Annual	Annual	Comments
Item	Cost \$	Measure	Rate	Measure	Use*	Cost	
Operating Labor							
Op Labor	69.56	\$/Hr	2.0 h	r/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 h	r/8 hr shift	816	\$ 56,734	\$/Hr, 1.0 hr/8 hr shift, 816 hr/yr
Maint MtIs	100%	of Maintenanc	e Labor		NA	\$ 56,734	100% of Maintenance Labor
Utilities, Supplies, Replacem	nents & Wast	te Manageme	nt				
Electricity	0.080	\$/kwh	262.1 k	W-hr	1,710,476	\$ 136,154	\$/kwh, 262.1 kW-hr, 6525.28365791702 hr/yr, 100%
Water			N/A g	pm			
Compressed Air	0.496	\$/kscf	2.0 s	cfm/kacfm	163,654	\$ 81,142	\$/kscf, 2.0 scfm/kacfm, 6525.28365791702 hr/yr, 10
Cooling Water			N/A g	pm			
Solid Waste Disposal	65.24	\$/ton	0.5 to	on/hr	3,507	\$ 228,801	\$/ton, 0.5 ton/hr, 6525.28365791702 hr/yr, 100% util
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%
Filter Bags	234.86	\$/bag	1,620 b	ags	N/A	\$ 102,608	\$/bag, 1,620 bags, 6525.28365791702 hr/yr, 100% u



replacing

utilization 00% utilizati

lization utilization 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?
Is the SNCR for a new boiler or retrofit of an existing boiler?	it 🗨	
Please enter a retrofit factor equal to or greater than 0.84 based on the difficulty. Enter 1 for projects of average retrofit difficulty.	he level of 1	
Complete all of the highlighted data fields:		
		Provide the following information for coal-fired boilers:
What is the maximum heat input rate (QB)?	175 MMBtu/hour	Type of coal burned: Sub-Bituminous
What is the higher heating value (HHV) of the fuel?	8,625 Btu/lb	Enter the sulfur content (%S) = 0.32 percent by weight
		or Select the appropriate SO ₂ emission rate: Not Applicable
What is the estimated actual annual fuel consumption?	42,518,000 lbs/Year	
		Ash content (%Ash): 5 percent by weight
Is the boiler a fluid-bed boiler?	No 🔻	
		For units burning coal blends:
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW	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 Fuel Cost
If the NPHR is not known, use the default NPHR value:	Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW	Coal Blend%S%AshHHV (Btu/lb)(\$/MMBtu)Bituminous01.849.2311,8412.4Sub-Bituminous00.415.848,8261.89Lignite00.8213.66,6261.74

Enter the following design parameters for the proposed SNCR:

	-			
Number of days the SNCR operates (t_{SNCR})	211	days	Plant Elevation	1440 Feet above
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			
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	Densities of typical SM	NCR reagents:
Number of days reagent is stored (t _{storage})	14	days	50% urea so	lution 7
Estimated equipment life	20	Years	29.4% aqueo	us NH ₃ 5
Select the reagent used	Ammonia			

Enter the cost data for the proposed SNCR:

	2010	
Desired dollar-year	2019	
CEPCI for 2019	607.5 Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering
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*	

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) = Administrative Charges Factor (ACF) =

0.015
0.03

71 lbs/ft³ 56 lbs/ft³

ing Plant Cost Index

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	and the ref
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/ga U.S. Geolog https://pub
			\$/gallon pr (510 \$/ton SOL / ft3 S(
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:	(0.0844 \$/k U.S. Energy
		https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	for MN ind https://ww pmt 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 \$/MN U.S. Energy Table 7.4. F https://ww
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/Ib)	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 listed unde https://ww

your own site-specific values, please enter the value used ference source ...

llon of 29% Ammonia)

gical Survey, Minerals Commodity Summaries, 2021

os.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. ice was back calculated.

NH3) / (2000 lb/ton NH3) * (0.29 lb NH3 / lb SOL) * (56 lb OL) / (7.48052 gal SOL / ft3 SOL) = \$0.554/gallon of 29%

(Wh)

Information Administration. Electric Power, January 2022 ustrial users. Available at: w.eia.gov/electricity/monthly/epm_table_grapher.php?t=e

/IBtu)

v Information Administration. Electric Power Annual 2020. Published March 2022. Available at: vw.eia.gov/electricity/annual/pdf/epa.pdf.

e rate is as of March 2, 2021 and is available as the rates r 'bank prime loan' at w.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}) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$	26	lb/hour
	(whre SR = 1 for NH_3 ; 2 for Urea)		
Reagent Usage Rate (m _{sol}) =	m _{reagent} /C _{sol} =	91	lb/hour
	(m _{sol} x 7.4805)/Reagent Density =	12.1	gal/hour
Estimated tank volume for reagent storage =	(m _{sol} x 7.4805 x t _{storage} x 24 hours/day)/Reagent	4 100	gallons (storage needed to store a 14 day reagent supply
	Density =	4,100	rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	(0.47 x NOx _{in} x NSR x Q _B)/NPHR =	3.3	kW/hour
Water Usage:			
Water consumption (q _w) =	$(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$	21	gallons/hour
Fuel Data:			
Additional Fuel required to evaporate water in	Hy x m x $((1/C_{})-1) =$	0.21	MMBtu/hour
injected reagent (∆Fuel) =	The A mreagent A ((-) Cinj) - A	0.21	initia cu i
Ash Disposal:			
Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1x10 ⁶)/HHV =	1.2	lb/hour
consumption (Δash) =	(Δfuel x %Ash x 1x10°)/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 x (B _{MW} x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF
For Fuel Oil and Natural Gas-Fired Utility Boiler	s:
SNC	$R_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers:	
SNCR _{cost} = 22	20,000 x (0.1 x Q _B x HRF) ^{0.42} x CoalF x BTF x ELEVF x RF
For Fuel Oil and Natural Gas-Fired Industrial Bo	ilers:
SNCR _{cc}	_{st} = 147,000 x ((Q _B /NPHR)x HRF) ^{0.42} x ELEVF x RF
SNCR Capital Costs (SNCR _{cost}) =	\$907,552 in 2019 dollars
	Air Pro-Heater Costs (APH)*
For Coal-Fired Utility Boilers	All Fre-heater Costs (AFR _{cost})
APH.	$= 69.000 \times (B_{WW} \times HBE \times CoalF)^{0.78} \times AHE \times BE$
For Coal-Fired Industrial Boilers:	SST CONCOUNT (DMW ATTER A COUNT) ANTER ATTE
APHaret	= 69.000 x (0.1 x Q ₂ x HRF x CoalF) ^{0.78} x AHF x RF
Air Pre-Heater Costs (APH _{cost}) =	\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired bo sulfur dioxide.	pilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of
	Balance of Plant Costs (BOP _{cost})
For Coal-Fired Utility Boilers:	
BOP _{cost} = 3	20,000 x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x BTF x RF
For Fuel Oil and Natural Gas-Fired Utility Boiler	s:
BOP _{cost}	= 213,000 x (B _{MW}) ^{0.33} x (NO _x Removed/hr) ^{0.12} x RF
For Coal-Fired Industrial Boilers:	
BOP _{cost} = 320	$0,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Industrial Bo	ilers:
BOP _{cost} = 2	213,000 x (Q _B /NPHR) ^{0.33} x (NO _x Removed/hr) ^{0.12} x RF
Balance of Plant Costs (BOP) =	\$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 =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$14,028 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$590 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$180 in 2019 dollars
Additional Fuel Cost =	Δ Fuel 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) ▼ percent by weight fault values for HHV and %S. Please enter the actual values for al value for any parameter is not known, you may use the HHV (Btu/lb) 1.84 0.41 8,82 ighted average

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 projects of average retrofit difficulty.	level of difficult	y. Enter 1 for		1			
Complete all of the highlighted data fields:							
	-				Provide the following in	formation for coal-f	ired boilers:
What is the maximum heat input rate (QB)?	l		175 MMBtu/ł	nour	Type of coal burned:	Sub-Bituminou	15 🔻
What is the higher heating value (HHV) of the fuel?	[8	8,625 Btu/lb		Enter the sulfur content	: (%S) =	0.32 p
What is the estimated actual annual fuel consumption?	[42,518	<mark>8,000</mark> lbs/year				
					Note: The table these paramete default values i	e below is pre-popul ers in the table belov provided	ated with def w. If the actu
Enter the net plant heat input rate (NPHR)	[10 MMBtu/N	мм			
					Coal	Type C	raction in loal Blend
If the NPHR is not known, use the default NPHR value:		Fuel Type Coal Fuel Oil Natural Gas	Default N 10 MMBt 11 MMBt 8.2 MMB	PHR :u/MW :u/MW tu/MW	Bitum Sub-Bitu Lig	ninous uminous nite	0 0 0
	L				Please click the values based or	calculate button to n the data in the tab	calculate wei le above.
Plant Elevation]		1440 Feet abov	ve sea level			
					catalyst replacement and 86 on the Cost Es	you may use either cost. The equation t imate tab. Please	er Method 1 ns for both i e select your

1 or Method 2 to calculate the methods are shown on rows 85 Ir preferred method:

- Method 1 O Method 2
- O Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	211 days	Number of SCR reactor chambers (n _{scr})	1	
Number of days the boiler operates (t _{plant})	211 days	Number of catalyst layers (R _{layer})	3	
Inlet NO _x Emissions (NOx _{in}) to SCR	0.39 Ib/MMBtu	Number of empty catalyst layers (R _{empty})	1	
Outlet NO _x Emissions (NOx _{out}) from SCR	0.06 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
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	650	°F
* For industrial boilers, the typical equipment life is between 20 and 25 years.		- Base sace fuel gas volumetric flow rate facto	tor (O) 516	ft ³ /min-MMBtu/hour
		Base case ruel gas volumetric now rate facto	tor (Q _{fuel})	
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default		
Density of reagent as stored (ρ_{stored})	56 Ib/cubic feet*	values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.		
Number of days reagent is stored (t _{storage})	14 days	Densit	ities of typical SCR reagents:	
		50% ur	urea solution	71 lbs/ft ³
		29.4%	% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SCR:

Select the reagent used

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemica
Annual Interest Rate (i)	3.5	Percent	
Reagent (Cost _{reag})	0.554	\$/gallon for 29% ammonia	
Electricity (Cost _{elect})	0.0844	\$/kWh	
		\$/cubic foot (includes removal and disposal/regeneration of existing	* \$227/cf is a defaul
Catalyst cost (CC _{replace})	227.00	catalyst and installation of new catalyst	if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a de

▼

Ammonia

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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 =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	60.16	tons/year
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.

70.776526

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 (Volestalyst) =			
, 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	(A) ^{0.5}	10.2	foot
reactor =	(A _{SCR})	10.2	leet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent
		_

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

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	100.08	kW
	where A = (0.1 x QB) for industrial boilers.		

Density =

t (MW) = 17.03 g/mole 56 lb/ft³

14 day reagent supply rounded to t

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 Invoctment (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:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (0.1 \text{ x} Q_{B} \text{ x} \text{ CoalF})^{0.92} \text{ x} ELEVF \text{ x} RF$	
SCR Capital Costs (SCR _{cost}) =		\$5,393,867 in 2019 dollars
	Passant Proparation Costs (PPC)	
For Coal-Fired Litility Boilers >25 MW:		
Tor courried officty boliers >25 WWW.	RPC = 564,000 x (NOx _{in} x B _{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NOx _{in} x Q _B x EF) ^{0.25} x RF	
Peagent Proparation Costs (PPC) -		\$1.741.116 in 2019 dollars
	Air Pre-Heater Costs (APHC)*	
For Coal-Fired Utility Boilers >25MW:		
	APHC = 69,000 x $(B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH) -		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers the	at hurn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide	30 III 2019 dollars
	Balance of Plant Costs (BPC)	
For Coal-Fired Utility Boilers >25MW:		

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

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

BPC = 529,000 x (0.1 x $Q_B x \text{ CoalF})^{0.42}$ ELEVF x 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 = $m_{sol} \times Cost_{reag} \times t_{op} =$		\$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): $n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		* 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 dir enter <1 for less difficult retrofits.	fficulty. Enter values >1 for more difficult	retrofits and 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	*Note: You do not need to enter a value for the	
THE VIS THE Weighted average value calculated using the values entered in the	e coal blend composition table.	HHV since you entered SO2 emissions in Ib/MMBtu above	
What is the estimated actual annual MWh output?	e coal blend composition table. 12,466 MWh	HHV since you entered SO2 emissions in lb/MMBtu above	
What is the estimated actual annual MWh output? Waste from a WFDG system disposed in an onsite or offsite landfill?	e coal blend composition table. 12,466 MWh frite Landfill	HHV since you entered SO2 emissions in Ib/MMBtu above	

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t _{ABS})	4380	Hours]		Plant Elevation		1440
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:							
						1	
Desired dollar-year for Capital Costs	2020				1		
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 should enter c	is the defau urrent bank p	It bank prime rate. User 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 0.0361 \$/kWh* Electricity (Cost_{elect}) Waste Disposal cost (Cost_{waste}) 30.00 \$/ton 60.00 \$/hour Labor Rate 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.

0 Feet above sea level

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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. Availabl 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. Availabl 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. Availabl 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. Availabl at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

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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 =	$SO_{2in} \times EF \times Q_B =$	70	lb/hour
Total SO_2 removed per year =	$(SO_{2in} \times EF \times Q_B \times t_{op})/2000 =$	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) =	$i (1+i)^n / (1+i)^n - 1 =$	0.0527
	Where n = Equipment Life and i= Interest Rate	

Waste Generation and Lime, Water and Power Consumption Rates:

Parameter	Equation	Calculated Value	Uni
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	kga
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	ton
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/l

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lons/hour
s/hour
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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 x 98,000 x ELEVF

 For Coal-Fired Utility Boilers 50 and 600 MW :

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

 SDA Capital Costs (ABS_{cost}) =

 \$5,259,580 in 2020 dollars

Reagent Prepara	tion 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 :	
BM	$F_{cost} = 338,000 \text{ x A}^{0.716} \text{ x (S x HRF)}^{0.2} \text{ x RF}$
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 x A x ELEVF	
For Coal-Fired Utility Boilers betwee 50 and 600 MW :		
	$BOP_{cost} = 899,000 \text{ x (A)}^{0.716} \text{ x (CoalF x HRF)}^{0.4} \text{ x ELEVF x RF}$	
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 Conta (DAC)		¢ 420 CZ2
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 Operato	r Cost) +(Annual Reagent Cost) + (Annual Make-up Water Cost) + (Annu	al Waste Disposal Cost) + (Annual Auxiliary
Annual Maintonanao Cost -		
Annual Maintenance Cost =	0.015 x TCI =	\$261,453
Annual Operator Cost =	0.015 x TCI = FT × 2,080 × Hourly Labor Rate	\$261,453 \$124,800
Annual Operator Cost = Annual Operator Cost = Annual Reagent Cost =	0.015 x TCI = FT × 2,080 × Hourly Labor Rate Q _{lime} x Cost _{reag} x t _{op} =	\$261,453 \$124,800 \$9,584
Annual Operator Cost = Annual Operator Cost = Annual Reagent Cost = Annual Electricity Cost =	0.015 x TCl = FT × 2,080 × Hourly Labor Rate $Q_{lime} \times Cost_{reag} \times t_{op} =$ P x Cost _{elect} x t _{op} =	\$261,453 \$124,800 \$9,584 \$13,081
Annual Maintenance Cost = Annual Operator Cost = Annual Reagent Cost = Annual Electricity Cost = Annual Make-up Water Cost =	0.015 x TCl = FT × 2,080 × Hourly Labor Rate $Q_{lime} x Cost_{reag} x t_{op} =$ P x Cost _{elect} x t _{op} = $q_{water} x Cost_{water} x t_{op} =$	\$261,453 \$124,800 \$9,584 \$13,081 \$6,471
Annual Maintenance Cost = Annual Operator Cost = Annual Reagent Cost = Annual Electricity Cost = Annual Make-up Water Cost = Annual Waste Disposal Cost =	0.015 x TCl = FT × 2,080 × Hourly Labor Rate $Q_{lime} x Cost_{reag} x t_{op} =$ P x Cost _{elect} x t _{op} = $q_{water} x Cost_{water} x t_{op} =$ $q_{waste} x Cost_{fuel} x t_{op} =$	\$261,453 \$124,800 \$9,584 \$13,081 \$6,471 \$5,283

	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 2

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 20	


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 of enter <1 for less difficult retrofits.	lifficulty. Enter values >1 for more difficult	t retrofits and 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
	percent of medicine		
Oulet SO ₂ Emissions (SO _{2out})	0.05 lb/MMBtu]	
Oulet SO ₂ Emissions (SO _{2out}) What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in t	0.05 lb/MMBtu Btu/lb ne coal blend composition table.	*Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above	
Oulet SO ₂ Emissions (SO _{2out}) What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in t What is the estimated actual annual MWh output?	0.05 lb/MMBtu Btu/lb be coal blend composition table. 12,466 MWh	<pre></pre>	
Oulet SO ₂ Emissions (SO _{2out}) What is the higher heating value of the fuel (HHV)? *HHV is the weighted average value calculated using the values entered in the What is the estimated actual annual MWh output? Waste from a WFDG system disposed in an onsite or offsite landfill?	0.05 lb/MMBtu Btu/lb he coal blend composition table. 12,466 MWh	<pre>> Note: You do not need to enter a value for the HHV since you entered SO2 emissions in Ib/MMBtu above]</pre>	

Enter the following design parameters for the proposed FGD System:

Number of hours the scrubber operates (t _{ABS})	4380	Hours]		Plant Elevation		1440
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:							
						1	
Desired dollar-year for Capital Costs	2020				1		
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 should enter c	is the defau urrent bank p	It bank prime rate. User 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 0.0361 \$/kWh* Electricity (Cost_{elect}) Waste Disposal cost (Cost_{waste}) 30.00 \$/ton 60.00 \$/hour Labor Rate 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.

0 Feet above sea level

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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. Availabl 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. Availabl 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. Availabl 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. Availabl at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

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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 =	$SO_{2in} \times EF \times Q_B =$	79	lb/hour
Total SO ₂ removed per year =	(SO _{2in} x EF x Q _B x t _{op})/2000 =	59.57	tons/year
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.

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Capital Recovery Factor:

Parameter	Equation	Calculated Value	
Capital Recovery Factor (CRF) =	$i (1+i)^{n}/(1+i)^{n} - 1 =$	0.0527 Wet FGD	System
	Where n = Equipment Life and i= Interest Rate		
		Mercury	Monitor
		0.1861 for Wast	ewater
		Treatmen	t System

Parameter	Equation	Calculated Value	U
Electricity Usage:			
Electricity Consumption (P) =	0.0112e ^{0.155xS} x CoalF x HRF x A x 1,000 =	222	k
Water Usage:			-
Water consumption (q _{water}) =	[(1.674 x S + 74.68) x A x CoalF x HRF]/1,000	1.4	k
Limestone Usage:			
Limestone consumption rate (Q _{Limestone}) =	[17.52 x A x S x HRF]/2,000] x (EF/0.98) =	0.07	t
Waste Generation:			┢
Waste generation rate (q _{waste}) =	[1.811 x Q _{Limestone} x (EF/0.98) =	0.1	t
Wastewater Flow Rate:			-
Wastewater flow rate (F) =	A x (0.4 gallons/min/MW) =	3	g

Jnits

W

gallons/hour

ons/hour

ons/hour

allons/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 a

	Wet FGD Capital Costs (ABS _{cost})
	$ABS_{cost} = 584,000 \text{ x (A)}^{0.716} \text{ x (CoalF x HRF)}^{0.6} \text{ x (S/2)}^{0.02} \text{ x ELEVF x RF}$
Wet FGD Capital Costs (ABS _{cost}) =	\$4,788,662 in 2020 dollars

	Reagent Preparation Costs (RPE _{cost})	
	RPE _{cost} = 202,000 x A ^{0.716} x (S x HRF) ^{0.3} x 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}) =

Balance of Plant Costs (BOP_{cost})

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

Balance of Plant Costs (BOP_{cost}) =

\$7,683,472 in 2020 dollars

\$538,892 in 2020 dollars

t offsite landfill

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 Was	te Disposal Cost + Annual Auxiliary Powe
Annual Maintenance Cost =	0.015 x TCI =	\$494,783
Annual Operator Cost =	FT × 2,080 × Hourly Labor Rate	\$187,200
Annual Reagent Cost =	$Q_{\text{limestone}} \times \text{Cost}_{\text{Limestone}} \times t_{\text{op}} =$	\$3,195
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$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 <i>,</i> 107 (w
Replacement Cost for Mercury Monitor =	CF _{mm} x MM _{Cost} =	\$18,610 (re
Direct Annual Cost =		\$808,174 in

	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	

	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 20

r Cost + Annual Wastewater

vith disposal at offsite landfill) eplaced once every 6 years.) 2020 dollars

2020 dollars

020 dollars

Data Inputs (MPCA FFA Costs, Virginia Department of Public Utilities, Boiler 11, SCR, 2022-05-05) ▼ percent by weight ault values for HHV and %S. Please enter the actual values for al value for any parameter is not known, you may use the HHV (Btu/lb) 1.84 0.41 8,82

Enter the following data for your combustion unit:				
Is the combustion unit a utility or industrial boiler?	istrial 🔻		What type of fuel does the unit	burn? Coal 💌
Is the SCR for a new boiler or retrofit of an existing boiler?	•			
Please enter a retrofit factor between 0.8 and 1.5 based on the level of d projects of average retrofit difficulty.	ifficulty. Enter 1 for	1		
Complete all of the highlighted data fields:				
			Provide the following information	on for coal-fired boilers:
What is the maximum heat input rate (QB)?	23	0 MMBtu/hour	Type of coal burned:	Lignite
What is the higher heating value (HHV) of the fuel?	4,51	.3 Btu/lb	Enter the sulfur content (%S) =	0.02 percent by weigh
What is the estimated actual annual fuel consumption?	263,816,00	0 <mark>0</mark> lbs/Year		
			For units burning coal blends: Note: The table below i these parameters in the default values provided	s pre-populated with default values for H e table below. If the actual value for any j
Enter the net plant heat input rate (NPHR)	1	.0 MMBtu/MW		
			Coal Type	Fraction in Coal Blend %S
If the NPHR is not known, use the default NPHR value:	Fuel Type Coal Fuel Oil Natural Gas	Default NPHR 10 MMBtu/MW 11 MMBtu/MW	Bituminous Sub-Bituminous Lignite	0 1.84 0 0.41 0 0.82
	Natural Gus		Please click the calculat values based on the dat	e button to calculate weighted average a in the table above.
Plant Elevation	144	O Feet above sea level		
			For coal-fired boilers, you ma catalyst replacement cost. Th and 86 on the Cost Estimate	y use either Method 1 or Method 2 t ne equations for both methods are sh tab. Please select your preferred me

1 or Method 2 to calculate the

methods are shown on rows 85 Ir preferred method:

- Method 1 O Method 2
- O Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	311 days	Number of SCR reactor chambers (n _{scr})	1
Number of days the boiler operates (t _{plant})	311 days	Number of catalyst layers (R _{layer})	3
Inlet NO _x Emissions (NOx _{in}) to SCR	0.15 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
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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*	Gas temperature at the SCR inlet (T)	650 °F
* For industrial boilers, the typical equipment life is between 20 and 25 years.		Base case fuel gas volumetric flow rate factor (Q_{fue}) 516 ft ³ /min-MMBtu/hour
Concentration of reagent as stored (C _{stored})	29 percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default	
Density of reagent as stored (ρ_{stored})	56 Ib/cubic feet*	values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.	
Number of days reagent is stored (t _{storage})	14 days	Densities of t	ypical SCR reagents:
		50% urea sol 29.4% aquec	ution 71 lbs/ft ³ us NH ₃ 56 lbs/ft ³

Enter the cost data for the proposed SCR:

Select the reagent used

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical
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 if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a defa
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a de

▼

Ammonia

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.

I Engineering Plant Cost Index

It value for the catalyst cost based on 2016 prices. User should enter actual value,

ault value for the operator labor rate. User should enter actual value, if known.

efault value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value
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
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.
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

If you used your own site-specific values, please enter the value used and the reference source ...

(\$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 / ft2 SOL) / (7 48052 gal SOL / ft2 SOL) = \$0 554 (gallop of 20% (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

(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 Ga	as
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}) =		827.40	Cubic fact
Cross continued error of the entry $(\Lambda - \lambda)$	2.81 X Q _B X EF _{adj} X Silpadj X NOX _{adj} X S _{adj} X (I_{adj}/N_{scr})	837.49	
Cross sectional area of the catalyst (A _{catalyst}) =	q _{flue gas} /(16ft/sec x 60 sec/min)	118	ft ⁻
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	(Λ) ^{0.5}	11 7	foot
reactor =	(A _{SCR})	11.7	leet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	50	feet

Reagent Data:

Type of reagent used

Ammonia

Molecular Weight of Reagent (MW) = Density =

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 2

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) ^{0.43} =	132.60	kW
	where $A = (0.1 \text{ x QB})$ for industrial boilers.		

17.03 g/mole 56 lb/ft³

14 day reagent supply rounded to the nearest 1

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
	<u></u>	: 2010

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:		
	$SCR_{cost} = 310,000 \text{ x} (NRF)^{0.2} \text{ x} (B_{MW} \text{ x HRF x CoalF})^{0.92} \text{ x ELEVF x RF}$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$	
		66 007 050 · 0040 · · · ·
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 x (NO x_{in} x B _{MW} x NPHR x EF) ^{0.25} x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	RPC = 564,000 x (NOx _{in} x Q _B x EF) ^{0.25} x 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 x (B _{MW} x HRF x CoalF) ^{0.78} x AHF x RF	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:		
	APHC = 69,000 x (0.1 x Q _B x CoalF) ^{0.78} x AHF x RF	
Air Pre-Heater Costs (APH) =		\$0 in 2019 dollars
* Not applicable - This factor applies only to coal-fired boilers tha	t burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.	\$0 III 2015 dollar5
	Delever of Direct Costs (DDC)	
For Coal-Fired Litility Boilers >25MW/:	Balance of Plant Costs (BPC)	

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

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

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