1. PURPOSE

Entergy has requested that S&L support their Best Available Retrofit Technology (BART) evaluation for Nelson Unit 6 with respect to SO_2 emissions. As part of this effort, Entergy has requested that S&L perform a technology evaluation and cost estimates to install an enhanced dry sorbent injection (DSI) system utilizing a baghouse in conjunction with the DSI system on Nelson Unit 6. System costs were scaled from other DSI projects recently completed. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the AACE Level 5 capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of SO_2 and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with SO_2 and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP). The performance of DSI technology has been shown to be enhanced by implementation with a downstream fabric filter or baghouse. A baghouse increases the overall residence time due to longer ductwork and additional contact through the filter cake which builds up on the bags. The additional residence time improves performance and in some applications has resulted in much higher achievable removal efficiencies than traditional DSI technology upstream of an existing ESP.

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of an ESP or baghouse) is a technology that has been tested using sodium-based sorbents. The SO_2 in the flue gas reacts to form sodium sulfate and sulfite. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain $NaSO_3$/$NaSO_4$ along with the unused sorbent and some fly ash. These wastes will be collected in a baghouse and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts, any fly ash collected with the DSI byproducts cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, injection lances, baghouse, and booster fans.
- On-site disposal of DSI byproduct, including flyash blending equipment for stabilization.
- Injection rates based on 80% SO_2 removal from an inlet concentration of 0.96 lb SO_2/MMBtu, based on the maximum 24-hour average emissions between 2012 and 2014 which is consistent with the range of coal sulfur. Either sodium bicarbonate (SBC) or Trona can be used as the DSI reagent; for the purposes of this estimate Trona was used as the design reagent as this requires a higher injection rate and is therefore a more conservative design basis for this system.
    - Annual operating costs will be based on 80% SO_2 removal from an uncontrolled SO_2 rate of 0.70 lb SO_2/MMBtu, based on the annual average emissions from 2012 to 2014.
    - The system will be designed to control emissions to meet a permit limit of 0.19 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.74 lb/MMBtu between 2012 and 2014.
- Reagent injection at the ESP outlet, upstream of a new baghouse to collect flyash separately and preserve flyash sales.
- Installation of a pulse jet fabric filter (PJFF) downstream of the existing ESPs to assist in SO_2 removal efficiency and capture of the DSI byproduct.
- Installation of new booster fans to account for increased draft pressure loss mainly due to the baghouse.

- The cost estimate incorporates the results of a conceptual system design developed as input to the DSI estimate. The following items were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for Nelson Unit 6:
  - Auxiliary power consumption
  - Annual reagent consumption
  - Additional carbon consumption
  - Additional water consumption
  - Additional waste production
  - Reagent storage silos – quantity and size, based on 7 days storage
  - Byproduct storage silo
  - Quantity of mills
  - Quantity of blower trains

The fabric filter and ID fan equipment costs are scaled based on flue gas volume in comparison to industry data and recent budgetary cost estimates.

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- Sales Tax
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer

- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Interest During Construction
- Contingency
- Escalation

Cost Estimate 33592A provided in Attachment 1 represents the total cost to Entergy to install Enhanced DSI technology on Nelson Unit 6 including the EPC Contract price and all additional Owner's costs and third party services

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste)
- Reagent consumption
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- PJFF bag and cage replacement
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Estimate and Cost Estimate 33592A were developed using the assumptions and scope provided in this document. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of -20 to +50%.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following assumptions were made for the design basis for Nelson Unit 6 DSI System:

- Design SO_2 inlet concentration of 0.96 lb SO_2/MMBtu for equipment design.
- SO_2 inlet concentration of 0.70 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 80%.
- Permitted SO_2 Emission Limit of 0.19 lb SO_2/MMBtu
- Annual capacity factor of 62%, based on historical operating data.
- Reagent injection at the ESP outlet, upstream of the new baghouse
- Compliance deadline of June 2021.

4.1 TOTAL INSTALLED CAPITAL INVESTMENT

The primary scope of this project is to estimate the cost to install a DSI and baghouse system on Nelson Unit 6. The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The baghouse area equipment, ID fan equipment, and the remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by area below:

1. DSI System Area:
   a. Reagent unloading systems:
      - Two trains (2 x 100%)
      - Pneumatic pressure blowers (1 x 100%) per train
      - One dehumidifier and chiller per train

- Pneumatic conveying piping located on an above-grade sleeper pipe rack
- Unloading equipment is based on recent pricing for a similar project

b. Reagent Storage:

- Nine silos capable of storing approximately 7 days of sorbent, 3,150-tons storage total, including substructure
- 14' diameter and 125' high, each
- 350-tons working storage, each
- Continuous level detection systems
- Nine bin vent filters for nine silos
- Live bottom hopper outlets
- Rotary airlock assemblies

c. Reagent transfer systems:

- Three trains (3 x 50%)
- Pneumatic pressure blowers (1 x 100%) per train
- One dehumidifier and chiller per train

b. Reagent Milling

- One 7.5-tph mill per train
- One set of bypass piping per mill

c. Reagent Injection

- Splitters with piping to two ESP outlets
- Six injection lances per injection location

d. Concrete foundations including piles for all reagent silo, blower, and mill areas

e. Blower and mill area superstructures

f. Equipment pricing based on recent vendor pricing for a similar project

2. <u>Byproduct Handling</u>

a. One DSI by-product storage silo (approximately 7-day capacity) with bin vent filter, fluidizing system, and four unloading conditioners (pin mixers)

b. One common fly ash blending bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Concrete foundations including piles for silos

g. Continuous level detection system

h. One lot pneumatic conveying piping located on an above grade pipe rack

i. Two truck scales and substructure

j. Cost estimate based on a recent budgetary proposal for similar project

3. Baghouse Area

a. New baghouse, including pulse jet cleaning system and all appurtenances

b. One casing with 12 compartments

c. 10 meter bags and cages

d. 6” insulation with lagging

e. Enclosure around hopper area

f. Baghouse area foundations including 18” auger cast piles 60’ long

g. Equipment pricing based on recent pricing for similar projects

4. Ductwork and Supports

a. ID fan outlet to Baghouse inlet:
- Two ID fan outlet ducts, combine to a single duct to carry flue gas to the new baghouse
- Carbon steel, ¼ in.
- Velocity, 3,600 fpm

a. Baghouse outlet to Booster fans
- A single baghouse outlet duct which splits into two booster fan inlets.
- Carbon steel, ¼ in.
- Velocity, 3,600 fpm

b. Booster fan outlet to the stack inlet ductwork and supports:
- Two booster fan inlets, combine to a single duct which connects to the existing chimney breeching duct.
- Carbon steel, ¼ in.
- Velocity, 3,600 fpm

c. Dampers and expansion joints

d. 6” insulation and lagging

e. Steel support structure and concrete mat foundations for all new flue gas ductwork

5. ID Booster Fans
    a. Two, approximately 2,600 hp, axial booster fans sized to overcome pressure drop associated with baghouse
    b. Includes motors - no spare motor included
    c. Booster fan area foundations

6. Civil Work
    a. Site grading
    b. Soil removal earthwork
    c. Excavation, backfill, and compaction for all foundations
    d. Development of a new laydown area, approximately 3 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

7. Mechanical Work
    a. Allowance of $2,000,000 provided for mechanical systems including transport piping, pipe rack, instrument/service air, and other miscellaneous items based on recent in-house cost estimates for similar projects

8. Demolition and Relocation
    a. Allowance of $1,000,000 is provided for demolition and relocation of existing equipment that may interfere with the new DSI system and baghouse based on recent in-house cost estimates for similar projects

9. Electrical
    a. Allowance of $16,500,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects

10. Instrumentation
    a. Allowance of $2,700,000 is provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects

11. Labor Costs

    Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

    a. Labor Wage Rates

       Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for

Lake Charles area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.1 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Louisana. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. <u>Other Direct and Construction Indirect Costs</u>

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables
b. Premiums and per diems ($10 per hour)
c. Overtime is included based on five 10-hour shifts per week work schedule
d. Freight on construction materials
e. Sales Tax (included at a rate of 9.75% on all material costs)
f. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)
g. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. <u>EPC Indirect Costs</u>

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $10,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $150,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 300 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $400,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install Enhanced DSI at Nelson 6 based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost, excluding escalation.

b. Construction management support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the Construction Management Support was estimated to be $2,500,000.

c. Startup and commissioning support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $350,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $2,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for outside assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $200,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of Enhanced DSI (with a baghouse) at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.2 VARIABLE OPERATING AND MAINTENANCE COSTS

In order to achieve a higher removal rate of approximately 80%, the installation of a baghouse was added to the project since the existing ESPs are not sufficient for the reagent injection rates required for this high SO_2 removal. The filter cake on the bags increases SO_2 removal. The following unit costs were used to develop the variable O&M costs. All of these values, with the exception of the reagent costs and the typical bag and cage costs, were provided by Entergy. The reagent and bag costs are based on recent in-house pricing.

Table 1: Unit Pricing for Utilities

Unit Cost	Units	Value
Trona	$/ton	275.00
Low Quality Water	$/1000 gal	0.50
Bag Cost [1]	$/bag	100.00
Cage Cost [1]	$/cage	30.00
Waste Disposal	$/ton	7.50
Aux Power Cost	$/MWh	40.00

Note 1: Bags will be replaced every 3 years and cages will be replaced every 9 years

Table 2 below summarizes the consumption rates estimated as well as the first year variable O&M costs.

Table 2: Variable O&M Rates and First Year Costs

DSI System Parameters	**Units**	**Value**
Reagent Consumption	lb/hr	24,200
DSI Waste Production	lb/hr	19,300
Aux Power Consumption	kW	6,500
Low Quality Water Consumption	gpm	5
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	18,072,000
Waste Disposal Cost	$/year	393,000
Aux Power Cost	$/year	1,412,000
Low Quality Water Cost	$/year	800
Bag and Cage Replacement Cost	$/year	1,027,000
Total First Year Variable O&M Cost	**$/year**	**20,804,800**

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 62%.

4.3 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for a DSI and baghouse system are 5 personnel.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.1% of total EPC cost.

Table 3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 3: Fixed O&M First Year Costs

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$593,000
Maintenance Material	$/year	$1,362,000
Maintenance Labor	$/year	$908,000
Total First Year Fixed O&M Cost	**$/year**	**$2,863,000**

Note 1: First year costs are provided in $2015.

Note 2: Operating labor costs are based on a labor rate of $57 (provided by Entergy), with 5 operators working 40 hours/week.

5. ATTACHMENTS

1. Entergy Louisiana - Nelson Station - Unit 6 Enhanced DSI (with Baghouse) System - EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 33592A.

ENTERGY LOUISIANA
NELSON STATION - UNIT 6
ENHANCED DSI (WITH BAGHOUSE) SYSTEM - EPC

Estimator	A. KOCI
Labor rate table	15LALAK
Project No.	13027-003
Estimate Date	11/04/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33592A
Cost index	LALAK

Group	Phase	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
11.00.00		DEMOLITION						
	11.99.00	DEMOLITION, MISCELLANEOUS	1,000,000					1,000,000
		DEMOLITION	1,000,000					1,000,000
21.00.00		CIVIL WORK						
	21.14.00	STRIP & STOCKPILE TOPSOIL				2,128	367,534	367,534
	21.17.00	EXCAVATION				2,987	221,620	221,620
	21.39.00	STORM DRAINAGE UTILITIES			71,500	2,200	172,783	244,283
	21.41.00	EROSION AND SEDIMENTATION CONTROL			392,293	1,216	114,930	507,223
	21.53.00	PILING			1,288,854	17,198	1,832,793	3,121,647
	21.54.00	CAISSON			267,408	3,485	371,412	638,820
	21.99.00	CIVIL WORK, MISCELLANEOUS			234,000	2,640	195,908	429,908
		CIVIL WORK			2,254,055	31,854	3,276,980	5,531,035
22.00.00		CONCRETE						
	22.13.00	CONCRETE			1,292,830	43,286	2,745,200	4,038,030
		CONCRETE			1,292,830	43,286	2,745,200	4,038,030
23.00.00		STEEL						
	23.13.75	SILO		275,000		2,717	192,845	467,845
	23.15.00	DUCTWORK			2,925,000	59,406	6,067,723	8,992,723
	23.21.00	GIRDER			1,219,500	14,851	1,329,951	2,549,451
	23.25.00	ROLLED SHAPE			1,447,600	9,364	838,558	2,286,158
		STEEL		275,000	5,592,100	86,339	8,429,076	14,296,176
24.00.00		ARCHITECTURAL						
	24.35.00	PRE-ENGINEERED BUILDING			30,000	220	19,703	49,703
	24.37.00	ROOFING			81,972	485	29,108	111,080
	24.41.00	SIDING			267,663	3,082	272,992	540,655
	24.99.00	ARCHITECTURAL, MISCELLANEOUS			55,325	1,529	116,672	171,997
		ARCHITECTURAL			434,960	5,315	438,475	873,435
26.00.00		MISCELLANEOUS STRUCTURAL ITEM						
	26.13.00	CONCRETE SILO	4,940,000	40,000		0		4,980,000
		MISCELLANEOUS STRUCTURAL ITEM	4,940,000	40,000		0		4,980,000
31.00.00		MECHANICAL EQUIPMENT						
	31.27.00	DAMPERS & ACCESSORIES		240,000		1,408	143,828	383,828
	31.33.00	EXPANSION JOINT			457,500	5,033	514,071	971,571
	31.35.00	FANS & ACCESSORIES (EXCL HVAC)		4,300,000		7,701	488,691	4,788,691
	31.57.00	PARTICULATE REMOVAL		15,000,000			13,800,000	28,800,000
	31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS	2,000,000	11,500,000			10,600,000	24,100,000
		MECHANICAL EQUIPMENT	2,000,000	31,040,000	457,500	14,142	25,546,589	59,044,089
33.00.00		MATERIAL HANDLING EQUIPMENT						
	33.13.00	BYPRODUCT HANDLING EQUIPMENT		6,025,000		51,861	3,680,603	9,705,603
	33.57.00	SCALE		91,000		220	13,963	104,963
		MATERIAL HANDLING EQUIPMENT		6,116,000		52,081	3,694,565	9,810,565
34.00.00		HVAC						

Group	Phase	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
	34.37.00	DUST COLLECTOR	75,400					75,400
		HVAC	75,400					75,400
35.00.00		PIPING						
	35.14.10	CARBON STEEL, STRAIGHT RUN			89,280	1,366	116,917	206,197
		PIPING			89,280	1,366	116,917	206,197
36.00.00		INSULATION						
	36.13.00	DUCT			1,528,293	58,199	3,269,593	4,797,886
	36.15.00	EQUIPMENT			273	9,296	522,245	522,518
		INSULATION			1,528,566	67,494	3,791,838	5,320,404
41.00.00		ELECTRICAL EQUIPMENT						
	41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS	16,500,000					16,500,000
		ELECTRICAL EQUIPMENT	16,500,000					16,500,000
44.00.00		CONTROL & INSTRUMENTATION						
	44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE	2,700,000					2,700,000
		CONTROL & INSTRUMENTATION	2,700,000					2,700,000
71.00.00		PROJECT INDIRECT						
	71.25.00	CONSULTANT, THIRD PARTY	150,000					150,000
		PROJECT INDIRECT	150,000					150,000
		TOTAL DIRECT	27,365,400	37,471,000	11,649,291	301,878	48,039,641	124,525,332

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	48,039,641		301,878
Material	11,649,291		
Subcontract	27,365,400		
Process Equipment	37,471,000		
	124,525,332	**124,525,332**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	3,362,768		
91-2 Cost Due To OT 5-10's	6,606,600		
91-4 Per Diem	3,018,800		
91-5 Consumables	480,400		
91-6 Freight on Material	582,500		
91-8 Sales Tax	2,393,300		
91-9 Contractors G&A	7,493,200		
91-10 Contractors Profit	3,746,600		
	27,684,168	**152,209,500**	
Indirect Costs:			
93-1 Engineering Services	10,000,000		
93-4 SU/S Parts/ Initial Fills	150,000		
93-5 Technical Field Advisors	400,000		
93-8 EPC Fee	16,276,000		
	26,826,000	**179,035,500**	
Escalation:			
96-1 Escalation on Material	2,184,400		
96-2 Escalation on Labor	15,981,200		
96-3 Escalation on Subcontract	6,454,000		
96-4 Escalation on Process Eq	5,302,000		
96-5 Escalation on Indirects	6,060,900		
	35,982,500	**215,018,000**	
Total EPC Cost		***215,018,000***	
Owner's Costs:			
99-1 Owner's Costs	14,322,900		
	14,322,900	**229,340,900**	
Third Party Services:			
100 CM Oversight	2,500,000		
101 Start-Up Oversight	350,000		
102 Owner's Engineer	2,750,000		
103 Performance Testing	175,000		
	5,775,000	**235,115,900**	
Project Contingency :			
110 Project Contingency	49,783,400		
	49,783,400	**284,899,300**	
Escalation Addition:			
120 Escalation on Lines 99-110	4,116,000		
	4,116,000	**289,015,300**	
Interest During Construction:			
130 Interest During Constr.	17,135,300		
	17,135,300	**306,150,600**	
Total		***306,150,600***	

Entergy®

NELSON UNIT 6

WET FGD COST ESTIMATE BASIS DOCUMENT

Revision 0
November 6, 2015
Project 13027-003

Prepared by

Sargent & Lundy LLC

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1. PURPOSE

Entergy has requested that S&L support the Best Available Retrofit Technology (BART) evaluation for Nelson Unit 6 with respect to SO_2 emissions. As part of this effort, Entergy has requested that S&L perform a technology evaluation and cost estimates to install a new wet flue gas desulfurization (FGD) system on Nelson Unit 6. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) cost estimate and the AACE Level 5 capital cost estimate.

2. TECHNOLOGY DESCRIPTION

Wet FGD systems have been operating in utility applications for over 40 years. The term wet FGD refers to a system using an absorber that adiabatically saturates the inlet flue gas with water. The saturated flue gas allows for quick mass transfer of SO_2 into the reagent slurry droplets. The reagent used for the wet FGD process is typically limestone. The wet FGD process is most applicable to medium- to high-sulfur coals where 95-99% removal of the inlet SO_2 is required but can be applied to low-sulfur coals.

SO_2 is absorbed by the limestone slurry in the absorber vessel. The calcium in the limestone slurry reacts in the reaction tank with the absorbed SO_2 to form waste solids. With a forced oxidation environment, the waste solids are almost completely converted to calcium sulfate dihydrate ($CaSO_4 \cdot 2H_2O$), commonly known as gypsum. The chemical reactions are as follows:

$$CaCO_3 + SO_2 \Rightarrow CaSO_3 + CO_2$$

$$CaSO_3 + \tfrac{1}{2}O_2 \text{ (forced air)} + 2H_2O \Rightarrow CaSO_4 \cdot 2H_2O \text{ (>99\% of waste solids)}$$

Flue gas enters the wet FGD absorber below the slurry spray nozzles. The water in the limestone slurry absorbs the SO_2 from the flue gas as the slurry contact the flue gas. The slurry droplets accumulate in the bottom section of the absorber which is designed as a reaction tank. The reaction tank allows the absorbed SO_2 to react with the calcium in the limestone before the solution is recycled to the top of the absorber. Recycle is accomplished with dedicated slurry pumps for each absorber spray level.

A solids bleed stream is removed from the reaction tank to maintain the desired recycle slurry density. The solids bleed stream is first dewatered by hydroclones. The hydroclone underflow is further dewatered, generally with a vacuum belt filter, to achieve the required moisture concentration. By-product solids can be sold or landfilled.

Mist eliminators are used to remove any entrained slurry droplets before the saturated flue gas exits the absorber. The flue gas leaving the absorber is at the saturation temperature (120°F to 135°F) and fully saturated.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the FGD technology supplier providing the main process equipment as a complete FGD Island.
- The cost estimate incorporates the results of a conceptual system design developed as input to the FGD estimate. The following items were estimated based on previous projects and scaled for Nelson Unit 6:
    - Auxiliary power consumption
    - Annual reagent consumption
    - Additional water consumption
    - Additional waste production
    - Flue gas handling equipment, including ductwork and booster ID fans.
    - Reagent storage, handling and preparation equipment; including storage silos, ball mills, slurry tanks, and conveying equipment.
    - Absorber vessel and appurtenances, including but not limited to recycle pumps, spray levels and nozzles, tank agitators and mist eliminators.
    - Byproduct dewatering equipment; including but not limited to hydroclones, drum filters, and water reclaim tanks.
- For the purposes of this estimate, it was assumed that the wet FGD would be designed with suitable materials of construction to allow the system to operate as a closed loop system without requiring a chloride bleed stream. Based on this assumption, no waste water treatment equipment will be required for compliance with the new Effluent Limitation Guidelines.

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs

- Freight
- Sales Tax
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 33594A provided in Attachment 1 represents the total cost to Entergy to install DSI technology on Nelson Unit 6 including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Byproduct waste disposal
- Reagent consumption
- Auxiliary power consumption
- High quality and low quality make-up water consumption
- Operating labor
- Maintenance material and labor

The O&M Estimate and Cost Estimate 33594A were developed using the assumptions and scope provided in this document. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of -20 to +50%.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following assumptions were made for the design basis for the Nelson Unit wet FGD System:

- Design SO_2 inlet concentration of 0.96 lb SO_2/MMBtu for equipment design.
- SO_2 inlet concentration of 0.70 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of approximately 96%.
- SO_2 Outlet Emission of 0.04 lb SO_2/MMBtu.
- Annual capacity factor of 62%, based on historical operating data.
- Reagent delivery by truck.
- Compliance deadline of June 2021.

4.1 TOTAL INSTALLED CAPITAL INVESTMENT

The primary scope of this project is to estimate the cost to install a wet FGD system on Nelson Unit 6. The wet FGD system supplier will provide all of the major components within the FGD Island including the absorber vessel and internals and ID booster fans as well as equipment related reagent storage and preparation and byproduct dewatering. The remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the FGD system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by area below:

1. Wet FGD Island

   a. Reagent Preparation System:
      - Reagent Preparation Building, 100' x 70', including mat foundation and superstructure
      - Limestone day silos (2 x 100%)
      - Ball mills (2 x 100%)
      - One make up water tank for reagent preparation
      - One slurry storage tanks
      - Two (2) x 100% slurry pumps
      - Sump pumps and agitators
      - Equipment cost is based on recent pricing for a similar project.

   b. Absorber Area:
      - One 61' absorber vessel with all internals, including mat foundation.
      - Vessel tank surface constructed with A255 material with C276 wet/dry interface and absorber outlet
      - Absorber building, 110' x 110', including mat foundation and superstructure
      - Oxidation air blowers and ducting
      - Four (4) recycle pumps and piping
      - Two (2) oxidation air blowers
      - Heating and ventilation
      - Sump pumps and agitators
      - Equipment cost is based on recent pricing for a similar project.

   c. Limestone Storage and Handling
      - Limestone Truck Unloading
        - Enclosed truck unloading building
        - One limestone truck unloading hopper
        - One limestone 36" x 15'long truck hopper belt feeder
      - Limestone stackout conveyor, reclaim conveyor, and silo feed conveyor including the following:
        - Conveyor accessories with chute work
        - Magnetic separator and chute work
        - Belt scale
        - Telescopic chute

   - Mat foundations
- Two limestone day silos
   - Bin vent filter and discharge ducting, one per silo
   - Silo Level monitoring radar, one per silo
   - Silo level switches, on per silo
   - Bin Activators, one per silo
   - Cut off gate, one per silo,
- Dust suppression system at truck hopper, stackout conveyor, and reclaim conveyor.
- Equipment cost is based on recent pricing for a similar project.

d. Dewatering System

- Dewatering Building, 100’ x 100’, including mat foundations and superstructure
- Reclaim water system including tank, pumps and agitator
- Gypsum slurry surge tank
- Primary hydroclone classifiers
- Two (2) x 100% Drum Filters
- Sump pumps and agitators
- Equipment cost is based on recent pricing for a similar project.

2. Gypsum Byproduct Storage Area

a. Material Conveyors to pile
b. Two gypsum conveyors
c. Gypsum Transfer conveyor
d. Belt scale at Gypsum transfer conveyor
e. Gypsum Radial Stack out conveyor with Telescopic chute
f. Gypsum storage pile
g. Mat foundation of all new structures
h. Truck loading and equipment

3. Flue Gas Handling System

a. Booster fan outlets to absorber inlet ductwork and supports:

- Two ID fan outlet ducts, combine to a single duct to carry flue gas to the new absorber inlet.
- Carbon steel, ¼ in.
- Velocity, 3,600 fpm

b. Absorber outlet to chimney breaching ductwork and supports:
   - A single duct from the absorber vessel which connects to the new chimney breeching
   - FRP
   - Velocity, 3,600 fpm

c. Dampers and expansion joints

d. 6” insulation and lagging

e. Steel support structure and concrete mat foundations for all new gas ductwork.

4. ID Booster Fans

   a. Two, approximately 3,300 hp, axial booster fans sized to overcome pressure drop associated with wet FGD

   b. Includes motors - no spare motor included

   c. Booster fan area foundations

5. Chimney

   a. 500 ft. chimney with FRP liner

   b. Interior elevators

   c. Circular breech

   d. New concrete mat foundation

   e. Equipment cost is based on recent pricing for a similar project.

6. Civil Work

   a. Site grading

   b. Soil removal earthwork

   c. Excavation, backfill, and compaction for all foundations

   d. Storm sewer work

   a. Development of a new laydown area, approximately 5 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

7. Mechanical Work

   a. Interconnecting piping, above-ground

   b. Valves for interconnecting piping, above-ground

   c. Ball mill water storage tank, 24-hour storage capacity

   d. Mist eliminator make-up water tank, 1-hour storage capacity

e. Pipe Racks, including auxiliary steel and concrete foundations

f. BOP Pumps

- Two (2) x 100% mist eliminator water make-up pumps
- Two (2) x 100% ball mill make-up pumps
- Sump pumps

a. Instrument Air System

- Air compressors, 2 x 100%
- IA dryers w/filters; 2 x 100%
- Two air receivers
- Instrument air piping
- Heat-traced piping

b. Service Air System

- Air compressors, 2 x 100%
- Two air receivers

g. Eye wash and safety shower stations

h. Field painting

8. <u>Demolition and Relocation</u>

a. Allowance of $1,000,000 is provided for demolition and relocation of existing equipment and buildings based on recent in-house cost estimates for similar projects.

9. <u>Electrical</u>

a. Allowance of $26,400,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects, intended to include the following scope:

- Reserve auxiliary transformer (RAT)
- Isolated phase UAT tap bus extension
- One unit auxiliary transformer (UAT)
- Power Distribution Centers (PDC) including mat foundations and concrete piers
- Step-down transformers
- Medium-voltage cable bus duct
- Medium-voltage cable
- Low voltage, control and instrumentation cable
- Cable tray and conduit

- Grounding
- Lighting

10. Instrumentation

    a. Allowance of $4,500,000 is provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects. The allowance also includes costs associated with relocating and/or replacing the CEMS equipment from the old chimney to the new chimney. Controls System based on an estimated number of I/O points for the PLC based controls for the WFGD system:

    - Approximately 2,000 I/O points are required for the WFGD system
    - Approximately 2,000 I/O points for the balance of plant (BOP) system for the WFGD system which will also be based on PLC based control system

11. Labor Costs

    Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

    a. Labor Wage Rates

       Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Lake Charles area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.1 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Louisiana. The crew rates do not include an allowance for weather related delays.

    b. Labor crews

       Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

    In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

    a. Scaffolding and Consumables
    b. Premiums and per diems ($10 per hour)
    c. Overtime is included based on five 10-hour shifts per week work schedule

d. Freight on construction materials

e. Sales Tax (included at a rate of 9.75% on all material costs)

f. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)

g. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. <u>EPC Indirect Costs</u>

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $18,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of limestone was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The total cost of the initial fills was estimated to be $250,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 150 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $400,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. <u>Owner's Costs and Services</u>

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install wet FGD at Nelson 6 based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills

Owner's costs were included in the estimate at 8% of the total project cost, excluding escalation.

b. Construction management support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the Construction Management Support was estimated to be $3,500,000.

c. Startup and commissioning support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $420,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel

- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $4,000,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for outside assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of wet FGD at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.2 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy and are consistent with typical industry values. The reagent costs are based on recent in-house data from similar projects.

Table 3-1: Unit Pricing for Utilities

Unit Cost	Units	Value
Reagent (Limestone)	$/ton	40.0
Make-up Water Cost (High Quality)	$/1000 gal	1.25
Make-up Water Cost (Low Quality)	$/1000 gal	0.50
Byproduct Waste Disposal	$/ton	7.50
Aux Power Cost	$/MWh	40.00

Table 3-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the wet FGD system.

Table 3-2: Variable O&M Rates and First Year Costs

Wet FGD System Parameters	Units	Value
Reagent Consumption	lb/hr	7,300
Byproduct Waste Production	lb/hr	13,000
Aux Power Consumption	kW	10,250
Make-up Water Consumption (High Quality)	gpm	35
Make-up Water Consumption (Low Quality)	gpm	755
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	1,586,000
Byproduct Waste Disposal Cost	$/year	530,000
Aux Power Cost	$/year	4,454,000
Water Cost	$/year	275,000
Total First Year Variable O&M Cost	**$/year**	**6,845,000**

Note 1: First year costs are provided in $2015.

Note 2: First year costs are calculated using an annual capacity factor of 62%.

4.3 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the wet FGD system, the estimated staffing additions are 21 personnel. Operating Labor costs are estimated based on 4 shifts, 40 hours a week at an operator charge rate of $57/hour.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.1% of the total EPC cost. Table 3-3 below summarizes the first year fixed O&M costs for the design case.

Table 3-3: First Year Fixed O&M Costs for wet FGD

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor	$/year	2,490,000
Maintenance Material	$/year	2,109,000
Maintenance Labor	$/year	1,406,000
Total First Year Fixed O&M Cost	**$/year**	**6,005,000**

Note 1: First year costs are provided in $2015.

5. ATTACHMENTS

1. Entergy Louisiana - Nelson Station - Unit 6 Wet FGD Addition Conceptual Cost Estimate, Sargent & Lundy Estimate No. 33594A.

ENTERGY LOUISIANA
NELSON STATION - UNIT 6
WET FGD ADDITION EPC

Estimator	A. KOCI
Labor rate table	15LALAK
Project No.	13027-003
Estimate Date	11/04/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33594A
Cost index	LALAK

Group	Phase	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
11.00.00		DEMOLITION						
	11.99.00	DEMOLITION, MISCELLANEOUS	1,000,000					1,000,000
		DEMOLITION	1,000,000					1,000,000
21.00.00		CIVIL WORK						
	21.14.00	STRIP & STOCKPILE TOPSOIL				2,437	420,826	420,826
	21.17.00	EXCAVATION				3,483	399,273	399,273
	21.19.00	DISPOSAL				242	17,979	17,979
	21.20.00	BACKFILL			174,875	2,414	179,127	354,002
	21.39.00	STORM DRAINAGE UTILITIES			71,500	2,200	172,783	244,283
	21.41.00	EROSION AND SEDIMENTATION CONTROL			383,400	1,188	112,325	495,725
	21.53.00	PILING			1,780,800	23,762	2,532,356	4,313,156
	21.54.00	CAISSON			74,280	968	103,170	177,450
	21.99.00	CIVIL WORK, MISCELLANEOUS			390,000	4,400	326,513	716,513
		CIVIL WORK			2,874,855	41,095	4,264,352	7,139,207
22.00.00		CONCRETE						
	22.13.00	CONCRETE			1,199,300	21,130	1,340,088	2,539,388
	22.17.00	FORMWORK			79,153	6,966	601,315	680,468
	22.23.00	PRECAST			10,250	165	8,132	18,382
	22.25.00	REINFORCING			342,863	6,624	329,002	671,865
		CONCRETE			1,631,565	34,885	2,278,537	3,910,102
23.00.00		STEEL						
	23.15.00	DUCTWORK			3,718,050	31,959	3,264,266	6,982,316
	23.17.00	GALLERY			44,850	232	15,199	60,049
	23.25.00	ROLLED SHAPE			1,414,613	8,794	787,478	2,202,091
		STEEL			5,177,513	40,985	4,066,944	9,244,457
24.00.00		ARCHITECTURAL						
	24.33.00	PLUMBING FIXTURE			250,000	660	45,175	295,175
	24.99.00	ARCHITECTURAL, MISCELLANEOUS			8,826,000	66,018	5,911,876	14,737,876
		ARCHITECTURAL			9,076,000	66,678	5,957,051	15,033,051
25.00.00		CONCRETE CHIMNEY & STACK						
	25.13.00	CONCRETE CHIMNEY	12,900,000					12,900,000
		CONCRETE CHIMNEY & STACK	12,900,000					12,900,000
27.00.00		PAINTING & COATING						
	27.99.00	PAINTING & COATING, MISCELLANEOUS			6,000	660	30,297	36,297
		PAINTING & COATING			6,000	660	30,297	36,297
31.00.00		MECHANICAL EQUIPMENT						
	31.17.00	COMPRESSOR & ACCESSORIES		692,000		1,681	106,674	798,674
	31.25.00	CRANES & HOISTS			37,500	132	11,822	49,322
	31.33.00	EXPANSION JOINT		437,500		4,813	491,598	929,098
	31.35.00	FANS & ACCESSORIES (EXCL HVAC)		4,950,000		8,856	561,995	5,511,995
	31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM	750,000		96,000	429	26,980	872,980
	31.55.00	SO2 MITIGATION EQUIPMENT		38,900,000			35,907,000	74,807,000

Group	Phase	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
	31.75.00	PUMP		415,000		862	54,733	469,733
	31.83.00	TANK	405,000					405,000
	31.93.00	WATER TREATING		110,000		1,232	78,191	188,191
	31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS			98,490	1,733	148,265	246,755
		MECHANICAL EQUIPMENT	1,155,000	45,504,500	231,990	19,738	37,387,257	84,278,747
33.00.00		MATERIAL HANDLING EQUIPMENT						
	33.14.00	MATERIAL HANDLING EQUIPMENT			74,750	759	53,872	128,622
	33.21.00	CONVEYOR, COMPLETE		2,195,700		9,604	681,593	2,877,293
	33.31.00	DUST SUPPRESSION SYSTEM		750,000		2,310	163,957	913,957
	33.33.00	FEEDER		583,000		2,420	171,765	754,765
	33.35.00	MATERIAL FLOW CONTROL DEVICES		141,000		748	48,134	189,134
	33.41.00	MOBILE YARD EQUIPMENT		1,000,000		0	0	1,000,000
	33.57.00	SCALE	100,000	140,000		660	46,852	286,852
	33.63.00	TRAMP IRON DETECTOR		142,000		770	54,652	196,652
	33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS		164,000		528	33,510	197,510
		MATERIAL HANDLING EQUIPMENT	100,000	5,115,700	74,750	17,800	1,254,335	6,544,785
34.00.00		HVAC						
	34.15.00	AIR HANDLING UNIT		1,070,000		20,682	1,431,820	2,501,820
	34.55.00	VENTILATION UNIT & SYSTEM		164,000		660	45,696	209,696
		HVAC		1,234,000		21,342	1,477,516	2,711,516
35.00.00		PIPING						
	35.13.01	SS 304, ABOVE GROUND, PROCESS AREA			777,610	23,380	2,000,587	2,778,197
	35.13.10	CARBON STEEL, ABOVE GROUND, PROCESS AREA			750,115	32,817	2,808,136	3,558,251
	35.13.25	FRP, ABOVE GROUND, PROCESS AREA			747,770	22,847	1,955,025	2,702,795
	35.15.30	HDPE, BURIED			76,050	4,505	385,489	461,539
	35.15.36	DUCTILE IRON, BURIED			55,000	803	68,720	123,720
	35.35.00	PIPE SUPPORTS, HANGERS			232,275	8,518	728,851	961,126
	35.45.00	VALVES			1,828,650	7,846	671,390	2,500,040
		PIPING			4,467,470	100,715	8,618,198	13,085,668
36.00.00		INSULATION						
	36.13.00	DUCT			464,400	9,615	540,169	1,004,569
	36.15.00	EQUIPMENT			315	10,726	602,591	602,906
	36.17.03	PIPE, MINERAL WOOL W/ALUMINUM JACKETING			108,255	3,527	198,144	306,399
		INSULATION			572,970	23,868	1,340,903	1,913,873
41.00.00		ELECTRICAL EQUIPMENT						
	41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS		9,200,000	6,200,000		11,000,000	26,400,000
		ELECTRICAL EQUIPMENT		9,200,000	6,200,000		11,000,000	26,400,000
44.00.00		CONTROL & INSTRUMENTATION						
	44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE	4,500,000					4,500,000
		CONTROL & INSTRUMENTATION	4,500,000					4,500,000
		TOTAL DIRECT	19,655,000	61,054,200	30,313,113	367,766	77,675,391	188,697,704

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	77,675,391		367,766
Material	30,313,113		
Subcontract	19,655,000		
Process Equipment	61,054,200		
	188,697,704	**188,697,704**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	5,437,296		
91-2 Cost Due To OT 5-10's	10,577,500		
91-4 Per Diem	3,677,700		
91-5 Consumables	776,800		
91-6 Freight on Material	1,515,700		
91-8 Sales Tax	3,678,200		
91-9 Contractors G&A	13,307,700		
91-10 Contractors Profit	6,653,800		
	45,624,696	**234,322,400**	
Indirect Costs:			
93-1 Engineering Services	18,000,000		
93-4 SU/S Parts/ Initial Fills	250,000		
93-5 Technical Field Advisors	400,000		
93-8 EPC Fee	25,297,200		
	43,947,200	**278,269,600**	
Escalation:			
96-1 Escalation on Material	4,597,700		
96-2 Escalation on Labor	20,524,400		
96-3 Escalation on Subcontract	3,678,700		
96-4 Escalation on Process Eq	6,987,700		
96-5 Escalation on Indirects	7,991,700		
	43,780,200	**322,049,800**	
Total EPC Cost		***322,049,800***	
Owner's Costs:			
99-1 Owner's Costs	22,261,600		
	22,261,600	**344,311,400**	
Third Party Services:			
100 CM Oversight	3,500,000		
101 Start-Up Oversight	420,000		
102 Owners' Engineer	4,000,000		
103 Performance Testing	175,000		
	8,095,000	**352,406,400**	
Project Contingency :			
110 Project Contingency	77,156,700		
	77,156,700	**429,563,100**	
Escalation Addition:			
120 Escalation on Lines 99-110	4,661,300		
	4,661,300	**434,224,400**	
Interest During Construction:			
130 Interest During Constr.	57,692,600		
	57,692,600	**491,917,000**	
Total		***491,917,000***	

APPENDIX B. EPA COST SPREADSHEET PRINTOUTS FOR SCR AND SNCR

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 556 MW

What is the higher heating value (HHV) of the fuel? 8411 Btu/lb

*HHV value of 8411 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 2524536 MWhs

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

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

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

Plant Elevation 21 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.35 percent by weight

*The sulfur content of 0.35% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

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

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

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

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

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.203	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* 24,000 hours is a default value for the operating life of a catalyst. User should enter actual value, if known.

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	19	percent
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent	
Reagent ($Cost_{reag}$)	1.630	$/gallon for 50% urea	* $1.66/gallon is a default value for 50% urea. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh	* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.0000	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.0000	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.0000	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Site-specifc value
Electricity Cost ($/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	
Percent sulfur content for Coal (% weight)	0.35	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)	8411.00	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/.	Site-specifc value
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	7 - based on all known economic analyses completed for reasonable progress four-factor analyses in both the first and second planning periods

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) =	Bmw x NPHR =	5,560	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	4,870,560	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		2,524,536	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.518	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4541	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	75.4	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	850.68	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,931.27	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.94	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,745,298	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	134.47	/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 =		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* 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	0.3111	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})	20,416.15	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,860	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 $A_{catalyst}$	3,289	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	57.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	331	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,740	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	232	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	78,100	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	3179.61	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

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

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

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

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

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

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

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

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

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

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

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

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

Total Capital Investment (TCI) =	$0	in 2019 dollars

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}) =	$120,485,056	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,415,923	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$8,611,405	in 2019 dollars
Total Capital Investment (TCI) =	$172,266,101	in 2019 dollars

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

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

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

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

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

SCR Capital Costs (SCR_{cost}) =	$120,485,056 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

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

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

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

Reagent Preparation Costs (RPC) =	$3,415,923 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

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

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

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

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

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

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

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

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

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

Balance of Plant Costs (BOP_{cost}) =	$8,611,405 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$5,070,682	in 2019 dollars
Indirect Annual Costs (IDAC) =	$13,897,612	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$18,968,294	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 =	$861,331	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$1,720,289	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$521,181	in 2019 dollars
Annual Catalyst Replacement Cost =		$1,967,882	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2-Utility selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
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 =		$5,070,682	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) =	$12,964	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$13,884,648	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$13,897,612	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$18,968,294	per year in 2019 dollars
NOx Removed =	1,931	tons/year
Cost Effectiveness =	$9,822	per ton of NOx removed in 2019 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

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Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 556 MW

What is the higher heating value (HHV) of the fuel? 8411 Btu/lb

*HHV value of 8411 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 2524536 MWhs

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

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

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

Plant Elevation 21 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.35 percent by weight

*The sulfur content of 0.35% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

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

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

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

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

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.203	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* 24,000 hours is a default value for the operating life of a catalyst. User should enter actual value, if known.

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

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

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent	
Reagent ($Cost_{reag}$)	2.000	$/gallon for 50% ammonia	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh	* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.0000	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.0000	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.0000	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	Site-specifc value
Electricity Cost ($/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	
Percent sulfur content for Coal (% weight)	0.35	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)	8411.00	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/.	Site-specifc value
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	7 - based on all known economic analyses completed for reasonable progress four-factor analyses in both the first and second planning periods

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) =	Bmw x NPHR =	5,560	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	4,870,560	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		2,524,536	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.518	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4541	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	75.4	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	850.68	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,931.27	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.94	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,745,298	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	134.47	/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 =		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* 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	0.3111	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})	20,416.15	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,860	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 $A_{catalyst}$	3,289	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	57.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	583	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,166	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	123	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	41,300	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	3179.61	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

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

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

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

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

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

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

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

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

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

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

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

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

Total Capital Investment (TCI) =	$0	in 2019 dollars

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}) =	$120,485,056	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,415,923	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$8,611,405	in 2019 dollars
Total Capital Investment (TCI) =	$172,266,101	in 2019 dollars

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

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

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

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

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

SCR Capital Costs (SCR_{cost}) =	$120,485,056 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

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

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

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

Reagent Preparation Costs (RPC) =	$3,415,923 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

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

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

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

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

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

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

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

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

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

Balance of Plant Costs (BOP_{cost}) =	$8,611,405 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$4,465,966	in 2019 dollars
Indirect Annual Costs (IDAC) =	$13,897,612	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$18,363,577	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 =	$861,331	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$1,115,572	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$521,181	in 2019 dollars
Annual Catalyst Replacement Cost =		$1,967,882	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2-Utility selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
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 =		$4,465,966	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) =	$12,964	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$13,884,648	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$13,897,612	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$18,363,577	per year in 2019 dollars
NOx Removed =	1,931	tons/year
Cost Effectiveness =	$9,509	per ton of NOx removed in 2019 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

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

What type of fuel does the unit burn? Coal

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 556 MW

What is the higher heating value (HHV) of the fuel? 8,411 Btu/lb

*HHV value of 8411 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 2,524,536 MWhs

Is the boiler a fluid-bed boiler? No

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

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

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

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.35 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 0.35% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 5.84 percent by weight

*The ash content of 5.84% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

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

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,685	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})	365	days	Plant Elevation	21 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.203	lb/MMBtu		
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.15	lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	1.05		*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).	

Concentration of reagent as stored (C_{stored})	19	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7	Percent		
Fuel ($Cost_{fuel}$)	1.97	$/MMBtu		
Reagent ($Cost_{reag}$)	1.63	$/gallon for a 19 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0361	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Site-specifc value
Water Cost ($/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 ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf	
Fuel Cost ($/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.	Site-specifc value
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)	0.35	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)	8,411	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/.	Site-specifc value
Interest Rate (%)	5.5	Default bank prime rate	7 - based on all known economic analyses completed for reasonable progress four-factor analyses in both the first and second planning

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) =	Bmw x NPHR =	5,560	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	4,870,560	MWhs
Estimated Actual Annual MWh Output (Boutput) =		2,524,536	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.52	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4541	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	26	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	294.68	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	669.00	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 =		
Atmospheric pressure at 21 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

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

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	439	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	2,309	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	308.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	103,700	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	55.7	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	249	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	3.55	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	24.7	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$3,684,095 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$5,716,552 in 2019 dollars
Total Capital Investment (TCI) =	$12,220,842 in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$3,684,095 in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

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}) =	$5,716,552 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$2,514,147	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,159,147	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,673,293	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 =	$183,313	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$2,282,474	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,130	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$4,714	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$31,782	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$2,733	in 2019 dollars
Direct Annual Cost =		$2,514,147	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$5,499	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,153,647	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,159,147	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,673,293	per year in 2019 dollars
NOx Removed =	669	tons/year
Cost Effectiveness =	$5,491	per ton of NOx removed in 2019 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

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

What type of fuel does the unit burn? Coal

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 556 MW

What is the higher heating value (HHV) of the fuel? 8,411 Btu/lb

*HHV value of 8411 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 2,524,536 MWhs

Is the boiler a fluid-bed boiler? No

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

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

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

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.35 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 0.35% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 5.84 percent by weight

*The ash content of 5.84% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

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

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,685	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})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.203	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.15	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.42	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation	21	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019				
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent			
Fuel ($Cost_{fuel}$)	1.97	$/MMBtu			
Reagent ($Cost_{reag}$)	2.00	$/gallon for a 50 percent solution of urea			
Water ($Cost_{water}$)	0.0042	$/gallon*			
Electricity ($Cost_{elect}$)	0.0361	$/kWh*			
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*			

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf.	Site-specifc value
Water Cost ($/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 ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf	
Fuel Cost ($/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.	Site-specifc value
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)	0.35	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)	8,411	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/.	Site-specifc value
Interest Rate (%)	5.5	Default bank prime rate	7 - based on all known economic analyses completed for reasonable progress four-factor analyses in both the first and second planning

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) =	Bmw x NPHR =	5,560	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	4,870,560	MWhs	
Estimated Actual Annual MWh Output (Boutput) =		2,524,536	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.52	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4541	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	26	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	294.68	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	669.00	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 =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 21 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	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	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	1048	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	2,096	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	220.8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	74,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	75.5	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	1005	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	8.49	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1x10^6)/HHV =	58.9	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$3,684,095 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$5,716,552 in 2019 dollars
Total Capital Investment (TCI) =	$12,220,842 in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$3,684,095 in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

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}) =	$5,716,552 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$2,302,327	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,159,147	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,461,473	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 =	$183,313	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$2,005,173	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$12,369	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$19,020	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$75,923	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$6,529	in 2019 dollars
Direct Annual Cost =		$2,302,327	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$5,499	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,153,647	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,159,147	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,461,473	per year in 2019 dollars
NOx Removed =	669	tons/year
Cost Effectiveness =	$5,174	per ton of NOx removed in 2019 dollars

APPENDIX C. CLASS I AREAS MONITORING DATA SUMMARY REPORT

CLASS I AREAS IMPROVE MONITORING DATA SUMMARY

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1. INTRODUCTION AND BACKGROUND

This report summarizes the observed visibility impairment conditions for the Breton Island (originally "BRET", now referred to as "BRIS" or "BRIS1") and Caney Creek Wilderness ("CACR" or "CACR1") Class I areas from the Interagency Monitoring of Protected Visual Environments (IMPROVE) network monitoring data,[1] and compares these conditions to the unadjusted glidepath (a.k.a., uniform rate of progress or URP) and adjusted default, minimum, and maximum glidepaths for each area from EPA's September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling*.[2] In addition, the current visibility conditions for the clearest days are compared to projected (modeled) 2028 visibility for the clearest days.

1.1 Background

Visibility impairment or "haze" is described by the light extinction visibility metric in units of inverse megameters (Mm^{-1}). Because the inverse-distance units are difficult to conceptualize, the deciview haze index (dv) was developed. Extinction values are converted to deciviews using a logarithmic equation[3] such that the deciview scale is nearly zero for a pristine atmosphere, and, like the decibel scale for sound, equivalent changes in deciviews are perceived similarly across a wide range of background conditions.[4] Light extinction in the Class I areas is observed via the IMPROVE network of Class I area air monitors. IMPROVE visibility data are available on the IMPROVE website.[5]

EPA has selected the deciview scale as the most appropriate visibility metric for regulatory purposes because it is more conducive to describing and comparing humanly perceptible visibility changes at different Class I areas and for a wide range of visibility conditions. According to EPA, a one-deciview change represents a "small but noticeable change in haziness" and, depending on conditions, a change of greater than one deciview may be necessary to be perceived by the human eye.[6] Other studies, however, have suggested that a "1-deciview change never produces a perceptible change in haze."[7]

Section 169A of the Clean Air Act (CAA) sets forth a national goal for the "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." In 1999, the Regional Haze Program was promulgated to require states to include provisions to address impairment of visibility in Class I areas in their *State Implementation Plans*.[8] The Regional Haze Program requires setting reasonable progress goals towards achieving natural visibility conditions at each Class I area. The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the

[1] As of the drafting of this report, summarized annual IMPROVE monitoring data is available through the year 2018.

[2] https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

[3] Deciview = 10 × ln (Extinction ÷ 10)

[4] U.S. EPA, Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress at 1-5 - 1-7 (November 2001).

[5] http://vista.cira.colostate.edu/Improve/

[6] Regional Haze Regulations, 64 Fed. Reg. 35,725-27 (July 1999).

[7] Ronald C. Henry, "Just-Noticeable Differences in Atmospheric Haze," Journal of the Air & Waste Management Association, Vol. 52 at 1,238 (October 2002).

[8] 64 FR 35714

least impaired days over the same period.[9] Reasonable progress goals are compared to the Uniform Rate of Progress ("URP") or "glidepath" needed to achieve natural conditions in 2064.[10] The URP is a straight line from baseline visibility conditions (average of the 20 percent most impaired days as of 2004) to natural visibility conditions (to be achieved in 2064 for the 20 percent most impaired days). The second implementation planning period (2019-2028) for the regional haze efforts is currently underway. The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance)[11] provides guidance to states for the development of the implementation plans. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural (or "biogenic") and manmade (or "anthropogenic") sources of emissions. The EPA's *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program* (Visibility Guidance)[12] provides guidance to states on methods for selecting the twenty (20) percent most impaired days to track visibility and determining natural visibility conditions. This method has been applied by the IMPROVE group to the data collected at BRIS and CACR.

For the second planning period, the tracking of the 20 percent clearest days remains unchanged. The selection of the 20 percent clearest days does not include any processing to factor out natural sources of impairment. The tracking of the 20 percent clearest days is to ensure that the visibility on the clearest days is not being degraded.

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[9] 40 CFR 51.308(d)(1)

[10] 40 CFR 51.308(f)(1)(iv)(A)

[11] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

[12] Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, December 2018, EPA-454/R-18-010.

2. SUMMARY AND COMPARISON FOR BRETON ISLAND

The Breton Island Wilderness Area was established in 1904 as a National Wildlife Refuge. The Breton Island area consists of several barrier islands including Breton Island and the Chandeleur Islands in the Gulf of Mexico approximately 100 km east-southeast of New Orleans. The area islands are dynamic – their sizes and shapes constantly sculpted and shifted by currents, storms, and tides. Prior to a 1915 hurricane, Breton Island had a fishing village with a school and several homes. Hurricanes Rita and Katrina in 2005 eliminated much of the islands' topography. Today only wildlife inhabits the ever-shrinking islands as sea-level rise, subsidence, storms, wind, and waves reconfigure the coastal landmass.[13]

The original Breton Island IMPROVE monitor ("BRET1") operated from June 2000 to August 2005 and was located at 29.1189° N, -89.2066° E, which is near the end of the Mississippi Delta area to the southeast of New Orleans.[14] The site was destroyed during Hurricane Katrina.[15] A new monitor ("BRIS1") was established at 30.1086° N, -89.7617° E, which is east-northeast of New Orleans near Lake Catherine in St. Bernard Parish and started collecting valid data in January 2009.[16] Figure 2-1 show the relative locations of the two monitors and the approximate center of the Breton Island area ("Breton").

Figure 2-1. Locations of BRET and BRIS Monitors

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[13] https://www.fws.gov/refuge/Breton/ (paraphrased)

[14] Based on information obtained at http://vista.cira.colostate.edu/Improve/monitoring-site-browser/ (accessed on April 24, 2020).

[15] The IMPROVE Newsletter, Volume 14, No. 3, 3rd Quarter 2005 (http://vista.cira.colostate.edu/Improve/wp-content/uploads/2016/03/IMPNews3rdQtr2005.pdf)

[16] Ibid.

As shown in Figure 2-1, the location of BRIS, approximately 122 km from BRET and approximately 100 km from the Breton Island Class I area, is much closer to several industrial and population centers. The Regional Haze Program allows for the use of surrogate stations for Class I areas without actual monitors. However, an analysis should be conducted to show that the BRIS monitor is representative of the actual location of the Breton Island Class I area.

Table 2-1 presents a summary of the annual-average haze index values for each year from 2002 to 2018 for BRIS.

Table 2-1. Summary of Annual-Average Haze Index Values for BRIS

Year	Average of 20 Percent Most Impaired Days	Average of 20 Percent Clearest Days
2001	-- [A]	14.36 [A]
2002	-- [A]	13.92 [A]
2003	-- [A]	13.19 [A]
2004	-- [A]	14.33 [A]
2005	-- [A]	-- [A]
2006	-- [B]	-- [B]
2007	-- [B]	-- [B]
2008	-- [B]	-- [B]
2009	23.51	13.51
2010	23.69	15.28
2011	22.67	14.88
2012	-- [C]	-- [C]
2013	19.88	11.75
2014	21.58	12.85
2015	19.24	12.29
2016	17.61	11.81
2017	17.94	10.36
2018	18.55	11.74

[A] Represents data collected at BRET. Note that the data recovery was less than the required 75 %, and data substitution was used to fill in missing data. The yearly averages for the most impaired days are not available. However, EPA has established 24.91 as the baseline (2000-2004) average.
[B] No data collected.
[C] Summarized data are not available.

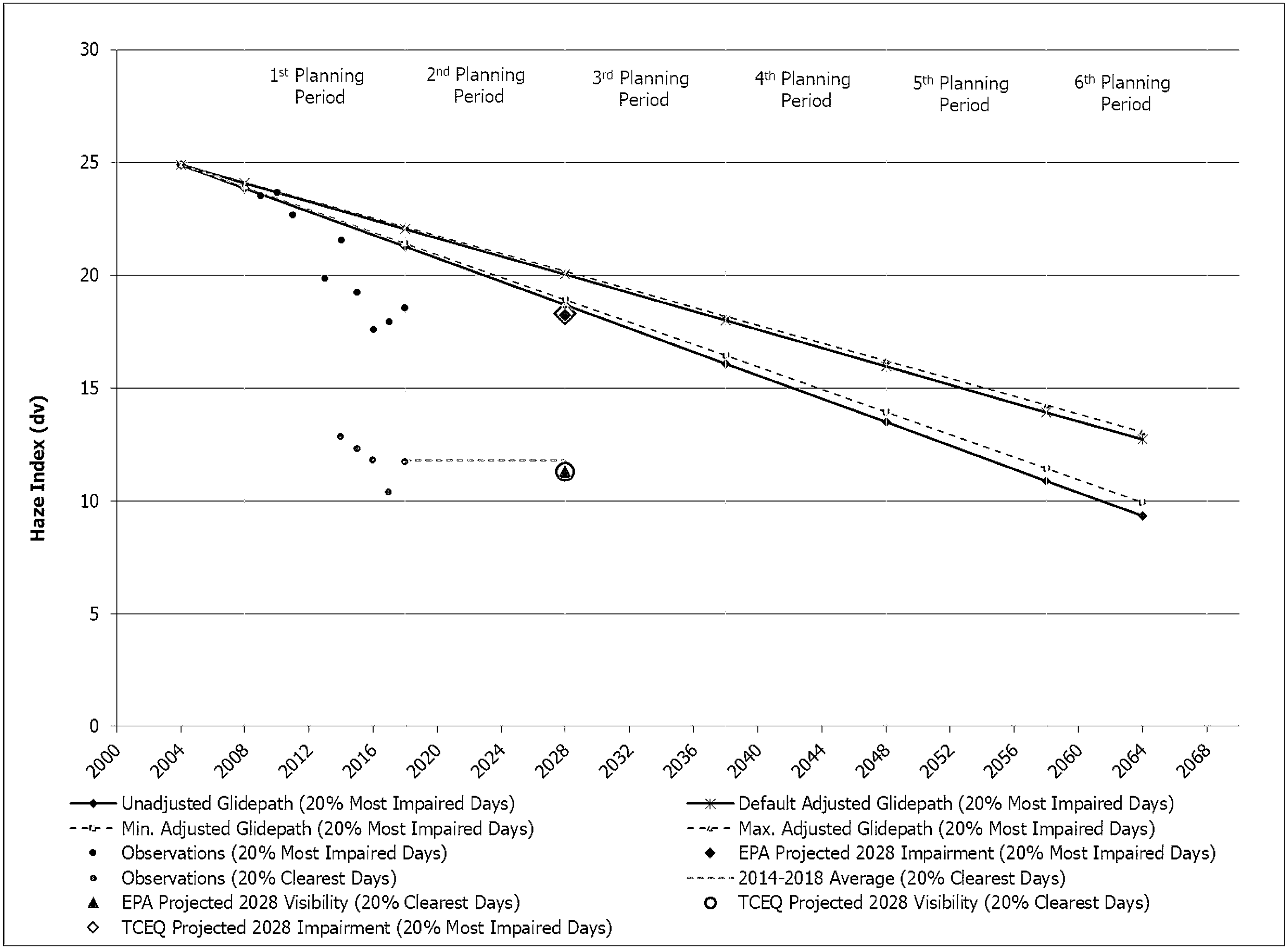
Figure 2-2 presents a comparison of the annual-average haze index values for the most impaired days from Table 2-1 to the Uniform Rate of Progress (URP) or glidepath proposed by EPA.[17] As seen in Figure 2-2, the actual observed visibility impairment at BRIS has declined sharply overall, continues to trend downward, and has remained below the glidepath since 2011. Thus, the current Class I area visibility conditions are better than necessary (or ahead of schedule) to achieve the goal of the regional haze program.

[17] Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling, September 19, 2019 (https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf)

In addition, the projected 2028 haze index values from EPA's September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling* are shown. EPA's modeling shows the projected 2028 haze index values are satisfying the objective of the Regional Haze Program to improve the most impaired days and not cause additional degradation to the clearest days. Lastly, the projected 2028 most-impaired days value from modeling completed by the Texas Commission on Environmental Quality (TCEQ) is also shown in the figure.[18] TCEQ conducted CAMx visibility modeling to assist with Step 6 of the SIP Guidance. It also indicates that the 2028 projected visibility impairment at BRIS1 is below the glidepath. Step 6 of the SIP Guidance is regional scale modeling of the long term strategy (LTS) to set the reasonable progress goals (RPGs) for 2028. The CAMx modeling conducted by EPA and TCEQ shows the projected 2028 haze index is below the unadjusted glide path. Therefore, the current projected emissions reductions are sufficient to show reasonable progress.

[18] Regional Haze Modeling to Evaluating Progress in Improving Visibility in and near Texas, dated January 21, 2020 (https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/pm/5822010567009-20200121-ramboll-RegionalHazeModelingEvaluateProgressVisibility.pdf)

Figure 2-2. Observations Compared to Glidepaths for BRIS



3. SUMMARY AND COMPARISON FOR CANEY CREEK

Table 3-1 presents a summary of the annual-average haze index values for each year from 2002 to 2018 for the Caney Creek Wilderness Area (CACR).

Table 3-1. Summary of Annual-Average Haze Index Values for CACR

Year	Average of 20 Percent Most Impaired Days	Average of 20 Percent Clearest Days
2002	25.15	11.88
2003	23.61	10.74
2004	23.21	11.11
2005	28.37	12.80
2006	23.77	12.51
2007	--[A]	-- [A]
2008	22.06	9.24
2009	22.48	8.09
2010	21.52	10.70
2011	20.83	11.83
2012	21.04	9.54
2013	19.46	8.61
2014	19.37	8.52
2015	18.17	7.03
2016	18.04	9.12
2017	18.57	8.32
2018	17.29	7.12

[A] Summarized data are not available for CACR for 2007.

Figure 3-1 presents a comparison of the annual-average haze index values for the most impaired days from Table 3-1 to the Uniform Rate of Progress (URP) or glidepath proposed by EPA for CACR.[19] As seen in Figure 3-1, the actual observed visibility impairment at CACR has declined sharply overall, continues to trend downward, and has remained below the glidepath since 2008. Thus, the current Class I area visibility conditions are better than necessary (or ahead of schedule) to achieve the goal of the regional haze program.

In addition, the projected (modeled) 2028 haze index values from EPA's September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling* are shown in the figure. EPA's modeling shows the projected 2028 haze index values are satisfying the objective of the Regional Haze Program to improve the most impaired days and not cause additional degradation to the clearest days. Lastly, the projected 2028 most-impaired days value from modeling completed by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS)[20]

[19] Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling, September 19, 2019 (https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf)

[20] VISTAS is the regional planning organization responsible for convening state, local, and tribal air pollution control agencies and collaborating on regional air quality analysis work necessary to support development of regional haze SIPs. VISTAS is comprised of the ten Southeastern States Air Resource Managers (SESARM) states (AL, FL, GA, KY, MS, NC, SC, TN, VA, and WV), the Eastern Band of Cherokee Indians, and Knox County, Tennessee.

is also shown in the figure.[21] VISTAS conducted CAMx visibility modeling to assist with Step 3 of the SIP Guidance[22], the selection of sources required to perform a Four-Factor Analysis. VISTAS used the PSAT (Particulate Matter Source Apportionment Technology) modeling option to quantify visibility impacts from individual sources. It also indicates that the 2028 projected visibility impairment at CACR is below the glidepath.

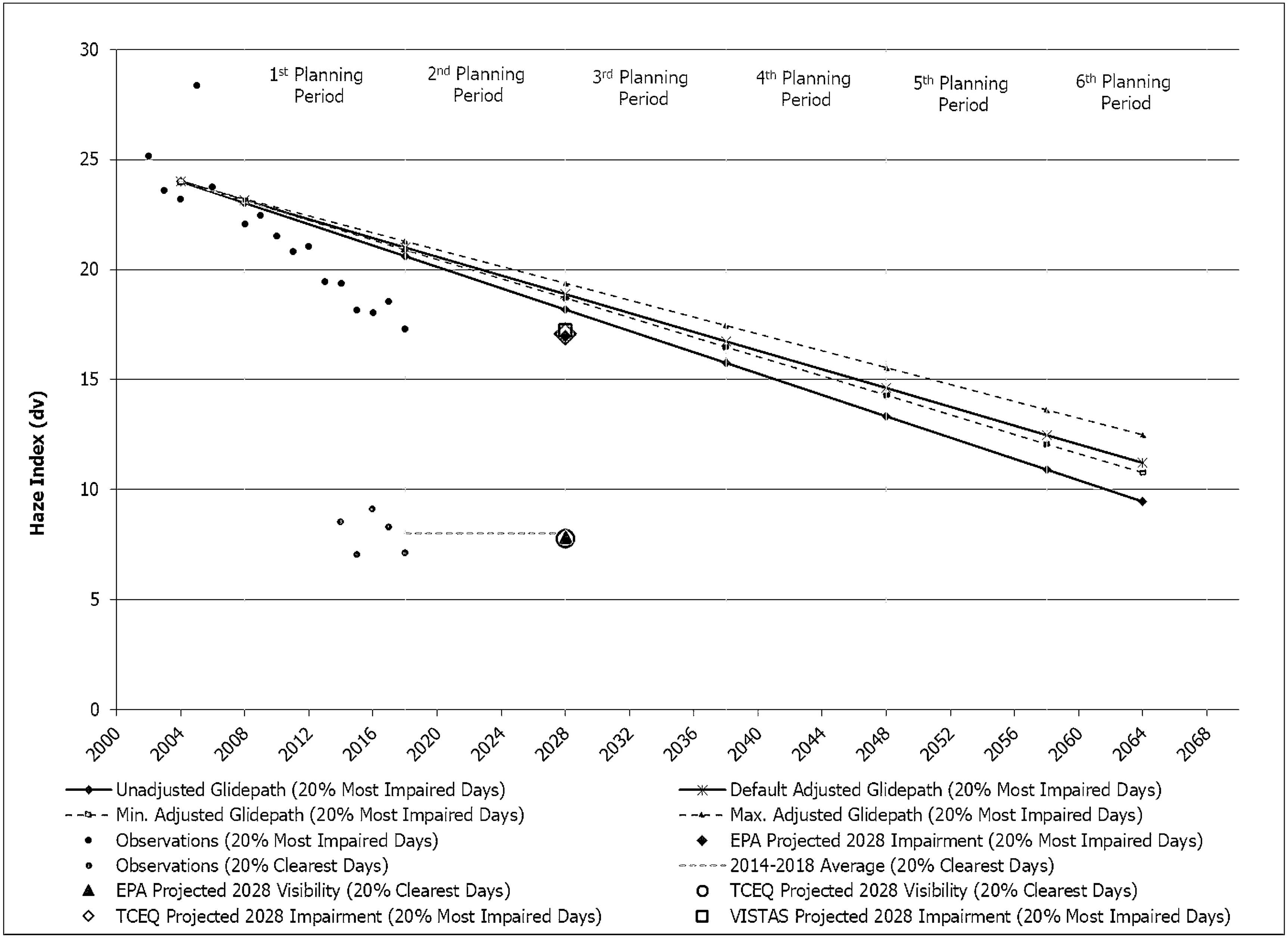
Step 6 of the SIP Guidance is regional scale modeling of the long term strategy (LTS) to set the reasonable progress goals (RPGs) for 2028. The CAMx modeling conducted by EPA and VISTAS shows the projected 2028 haze index is below the unadjusted glide path. Therefore, the current projected emissions reductions are sufficient to show reasonable progress.

---

[21] VISTAS Regional Haze Project Update, dated May 20, 2020 (https://www.metro4-sesarm.org/sites/default/files/VISTAS%20Pres%20Stakeholders%20Final%20200520.pdf)

[22] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

Figure 3-1. Observations Compared to Glidepaths for CACR



Entergy Services
Roy S. Nelson Electric Generating Plant

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BART Five-Factor Analysis
Produced in Response to Section 114 Request

Submitted to:

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1. EXECUTIVE SUMMARY

So as to comply with the recent Section 114 request from the Environmental Protection Agency (EPA) related to Louisiana Regional Haze[1] and without waiver of any claim or defense, including that the referenced units are not subject to BART based on the results of refined applicability analyses, this report documents a Best Available Retrofit Technology (BART) analysis for Entergy Gulf States Louisiana's (Entergy's) BART-eligible units at the Roy S. Nelson Electric Generating Plant (Nelson) located in Westlake, Louisiana (LA).

Entergy operates three BART-eligible units at Nelson:

- Unit 4 is an electric generating unit (EGU) boiler with a nominal heat input capacity of 5,400 MMBtu/hr that burns primarily natural gas and is equipped with flue gas recirculation equipment installed for control of NO_X emissions.
- Unit 6 is an EGU boiler with a nominal heat input capacity of 6,216 MMBtu/hr that burns primarily coal and is equipped with the following air pollution control devices (APCDs):
  - Electrostatic precipitator (ESP) with flue gas conditioning for PM control;
  - Separated Overfire Air (SOFA) Technology and a Low NO_X Concentric Firing System (LNCFS) for NO_X control;
- Auxiliary boiler (206 MMBtu/hr) for Unit 4 burns natural gas and fuel oil.

In response to EPA's Section 114 Request, Entergy submitted an initial BART-applicability screening analysis (Initial Screening Report) to Louisiana Department of Environmental Quality (LDEQ) and EPA Region 6 on August 31, 2015, which stated that, based on the results of a CALPUFF-based screening analysis and absent any further analysis, the Nelson Unit 4 boiler, Unit 6 boiler, and Auxiliary Boiler appear to be subject to BART. However, the Initial Screening Report also stated that, due to limitations inherent in the CALPUFF model when evaluating visibility impacts, limited chemistry mechanisms in the version used, potential over-prediction of nitrate contribution, and margin of error associated with the model, CALPUFF cannot reasonably be anticipated to predict any visibility impairment from the facility without additional analyses.

After submitting the Initial Screening Report, Trinity Consultants (Trinity) conducted additional applicability analyses, and submitted the results to EPA and LDEQ on November 9, 2015 (Updated Screening Report). In summary, the Updated Screening Report concludes that, although, BART guidelines recommend use of CALPUFF for BART eligibility determinations, due to several limitations and deficiencies (e.g., nitrate over-prediction, margin of error, distance limitation, etc.), the visibility impacts predicted by CALPUFF are not accurate. Per BART guidelines, Trinity used an alternate modeling system in the form of the Comprehensive Air Quality Model with Extensions (CAMx) to determine the individual and cumulative visibility contribution from Entergy's BART-eligible sources, including Nelson Unit 4, Unit 6, and Auxiliary Boiler. The results of this modeling indicate that even the maximum visibility impacts on the worst 20% days at both the Breton Wilderness Area (Breton) and the Caney Creek Wilderness Area (Caney Creek) are insignificant compared to the 0.5 deciview (dv) threshold utilized to established that a source "contributes" to visibility impairment at a Class I area. Specifically, as identified in the Updated Screening Report, the maximum visibility impact predicted for Nelson on the worst 20% days is 0.0116 dv at Breton, which is less than 1/40th the 0.5 dv threshold. Similarly, the maximum visibility impact predicted for Nelson on the worst 20% days is 0.0192 dv at Caney Creek, which is less than 1/25th of the 0.5 dv threshold. Therefore, emissions from the Nelson Plant cannot reasonably be

[1] Wren Stenger, Section 114(a) Information Request letter to Paul Castanon (Entergy Gulf States), May 19, 2015.

anticipated to cause or contribute to visibility impairment at any Class I area, and no BART analysis should be necessary, nor should BART controls be required for the units.

Nonetheless, to satisfy the terms of EPA's Section 114 Request, but without waiving any claim or defense, Entergy is submitting this BART Five-Factor Analysis. As requested in Enclosure 3, item a of the Section 114 Request, this report addresses emissions control alternatives for SO_2 and PM.

The BART Guidelines[2] state that a BART determination should address the following five statutory factors:

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

These five factors were considered in the BART analysis presented in this report. Furthermore, as specified in the BART Guidelines, the following five steps were used:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

Following are the results of the analysis for Nelson, which has been conducted in accordance with the BART Guidelines:

Generally, based on the predicted visibility impacts (CAMx), the visibility improvement that could be achieved through the installation and operation of controls at each of the Nelson units would be negligible, such that the cost of those controls could not be justified. Therefore, the facility's existing emission limits would satisfy BART for SO_2 and PM. Specifically by pollutant:

- SO_2 – No fuel changes or add-on controls would constitute BART.
- PM_{10} – No fuel changes or add-on controls would constitute BART.

[2] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR § 51.308 on July 6, 2005.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962, and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." For the purpose of determining which sources are subject to BART, a 1.0 dv change or more from an individual source is considered to "cause" visibility impairment, and a change of 0.5 dv is considered to "contribute" to impairment, which therefore establishes 0.5 dv as a numerical screening threshold for BART determinations.[3] Pursuant to the BART guidelines, the CALPUFF modeling system (CALPUFF) or any other appropriate dispersion model can be used to predict the visibility impacts. The model predicted visibility impact is compared to the 0.5 dv threshold to determine if the source is anticipated to cause or contribute to the visibility impairment.

Pursuant to the BART guidelines, for BART applicability determinations using CALPUFF, the 98th percentile visibility impact measured against natural background (and not maximum visibility impact) is compared to the 0.5 dv threshold.[4] Although, no such guidelines exist for alternate models such as CAMx, in a previous BART screening assessment conducted by the State of Texas, and approved by EPA Region 6, the maximum source contribution from individual sources was compared to the 0.5 dv threshold for the BART applicability determination.[5]

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

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[3] 70 Fed. Reg. 39104 (July 6, 2005)

[4] Ibid

[5] "Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility," 79 Fed. Reg. 74818, 74848 (Dec. 16, 2014).

> *"…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Specifically, the BART Guidelines state that a BART determination should address the following five statutory factors:

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

Further, the BART Guidelines indicate that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts

The BART guidelines allow the States to determine the "reasonably anticipated" visibility impairment using any other dispersion model in lieu of CALPUFF. Trinity conducted a CAMx based screening analysis for Nelson, the results of which were presented in the Updated Screening Report. The CAMx modeling predicted maximum baseline visibility impairment from the Nelson units at Breton and Caney Creek on the worst 20% days was infinitesimally smaller than the 0.5 dv threshold. Therefore, any improvement in visibility due to controls would be even more insignificant and could not be reasonably anticipated to result in visibility improvement at Breton or Caney Creek.

Trinity conducted a CALPUFF-based screening analysis for the Nelson units, the results of which were presented in the August 31, 2015, Initial Screening Analysis Report, The Initial Screening Analysis Report concluded that, based on the results of a CALPUFF-based screening analysis, the Unit 4 boiler, Unit 6 boiler, and Auxiliary Boiler appear to be subject to BART requirements. However, due to the limitations inherent in the CALPUFF model when evaluating visibility impacts; limited chemistry mechanisms in the version used, potential over-prediction of nitrate contribution, and margin of error associated with the model, CALPUFF cannot reasonably be anticipated to predict any visibility impairment from the facility without additional analysis. Due to CALPUFF's inherent limitations, Trinity subsequently conducted additional screening analyses, which were submitted in the Updated Screening Report. In summary, the Updated Screening Report concludes that, due to CALPUFF's inherent limitations and other issues, reliance on CALPUFF results to determine if Entergy's BART-eligible units are subject to BART is not appropriate and the additional applicability analyses demonstrate that the Nelson Unit 4, Unit 6, and Auxiliary Boiler are not subject to BART due to their exceedingly small predicted visibility impairment at the Class I areas. Specifically, the maximum visibility impact predicted for Nelson on the worst 20% days at Caney Creek is 0.0192 dv and at Breton is 0.0116 dv. Therefore, emissions from the Nelson Plant cannot reasonably be anticipated to cause or contribute to visibility impairment at any Class I area, and no BART analysis should be necessary, nor should BART controls be required for the units.

Although Entergy has concluded that the Nelson units are not subject to BART and that no BART five-factor analysis is required, EPA's Section 114 Request requires BART analyses for SO_2 and PM for those units determined to be subject to BART based on the results of CALPUFF modeling. To satisfy the requirements of EPA's Section 114 Request, but without waiving any claim or defense that the BART analyses are not necessary or appropriate in light of the insignificant contribution to visibility impairment at Caney Creek and Breton from the Nelson units that was presented in the Updated Screening Report, this report provides BART five-factor analyses for SO_2 and PM for each Nelson unit. The CALPUFF modeling referenced in this report was conducted according to the methodologies and procedures presented in the Initial Screening Report. The details of the Nelson Unit 4, Unit 6, and Auxiliary Boiler existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 3. The BART determinations for SO_2 and PM_{10} can be found in Sections 4 and 5, respectively.

3. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the existing (i.e. baseline) visibility impairment attributable to Nelson's Unit 4, Unit 6, and Auxiliary Boiler based on CALPUFF-based air quality modeling conducted by Trinity.

NELSON BASELINE EMISSION RATES

Table 3-1 summarizes the maximum 24-hour emission rates that were modeled for SO_2, NO_X[6], and PM_{10}, including the speciated PM_{10} emissions for 2012-2014 as was submitted in the Updated Screening Report. As noted in the Updated Screening Report, the baseline period was updated from 2000-2004 to 2012-2014 to reflect current operations.

Table 3-1. Nelson Refined Baseline Emission Rates (2012-2014)

Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Nelson, Unit 4	2.58	725.00	32.14	1.29	0.00	0.00	22.82	8.04
Nelson, Unit 6	6,178.42	1,565.75	155.08	10.38	71.88	55.38	15.31	2.13
Nelson, Aux. Boiler	106.76	56.55	3.46	0.63	0.74	1.83	0.11	0.15

Nelson Unit 4

The SO_2 and NO_x emission rates for Unit 4 were obtained from EPA's CAMD database and reflect the highest actual 24-hour emission rates based on 2012-2014 CEMS data from all natural gas combustion. The PM_{10} emission rate for Unit 4 was calculated with the maximum daily heat input from 2012-2014 CAMD data, and the AP-42 emission factor for natural gas.[7] The emission rates for the PM_{10} species reflect the breakdown of the filterable and condensable PM_{10} determined from AP-42 Table 1.4-2 *Combustion of Natural Gas.* All filterable PM was assumed to be elemental carbon, as this is the assumption that the NPS uses for filterable PM_{10} from natural gas fired combustion turbines, and the NPS does not have a speciation analysis specific to gas fired boilers. All of the condensable PM was assumed to be SOA, except for a small fraction of the condensable PM that was estimated to be SO_4. One-third of the estimated SO_2 emissions were separated and adjusted for differences in molecular weight to represent SO_4 emissions. This essentially double counts some of the fuel sulfur based emissions as SO_2 but also as SO_4. Since pipeline natural gas contains very little sulfur, both the SO_2 and SO_4 emission rates are very low.

Nelson Unit 6 (2012-2014)

The SO_2 and NO_x emission rates for Unit 6 were obtained from EPA's CAMD database and reflect the highest actual 24-hour emission rates based on 2012-2014 CEMS data. Total PM_{10} emission rates for Unit 6 are based on 2006 stack test data and the highest daily heat input value from CAMD. The emission rates for the PM_{10}

[6] NO_X is included herein as necessary for the model to predict visibility impairment.

[7] AP-42 Fifth Edition Chapter 1, Table 1.4-2 – Natural Gas.

species reflect the breakdown of the PM_{10} determined from the NPS "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[8]

An SO_4 emission rate was independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[9] This SO_4 rate was used in the modeling instead of the rate resulting from the NPS-based breakdown.

Nelson Auxiliary Boiler (2012-2014)

Since actual emissions data are not available for the auxiliary boiler, the modeled SO_2, NO_x, and PM_{10} emission rates remained the same as in the 2000-2004 baseline analysis, i.e., emission rates were set equal to the limits in Title V Permit No. 0520-00014-V2.

NELSON BASELINE VISIBILITY IMPAIRMENT

The BART guidelines recommend use of CALPUFF or another appropriate dispersion model to determine the visibility impairment from BART-eligible sources.[10] As noted above, Trinity submitted an Updated Screening Report exposing the inherent limitations and other issues of the CALPUFF modeling for the use of visibility analyses. Based on the analyses presented in the Updated Screening Report, Trinity concluded that CALPUFF modeling predicted visibility is not accurate and therefore should not be relied on for predicting visibility impairment at any of Entergy's BART-eligible emissions units. Instead, Trinity used CAMx, a more sophisticated and advanced photochemical model accepted widely and used by States and EPA as an appropriate model to predict the visibility impairment from sources for both BART as well as reasonable progress goals analysis.[11] Table 3-2 and Table 3-3 below present CAMx predicted average and maximum baseline contribution from Nelson units at Breton and Caney Creek, respectively, for the worst 20% days in 2002.

Table 3-2. Average and Maximum Impairment from Nelson Units at Breton for Worst 20% days

Emission Source	CAMx Predicted Contribution on Worst 20% Days	
	Average (dv)	Maximum (dv)
Nelson Unit 4	0.000	0.000
Nelson Unit 6	0.009	0.012
Nelson Auxiliary Boiler	0.000	0.000
Nelson Facility Cumulative Impact	0.009	0.0116

[8] The NPS Workbook, "PC Dry Bottom ESP Example.xls" updated 03/2006, was obtained from the NPS website: http://www.nature.nps.gov/air/Permits/ect/index.cfm. The following parameters were input into the workbook for speciation determination: total PM_{10} emission rate of 155.1 lb/hr, heat value of 8,579 Btu/lb, sulfur content of 0.30%, ash content of 5.37%.

[9] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

[10] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR Part 51, Section 308 on July 6, 2005

[11] CAMx was used by Texas for BART screening analysis and also by EPA in recent Reasonable Progress analysis for the Oklahoma and Texas Regional Haze Federal Implementation Plan.