Table 3-3. Average and Maximum Impairment from Nelson Units at Caney Creek 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	0.013	0.019
Nelson Unit 4 Auxiliary Boiler	0.000	0.000
Nelson Facility Cumulative Impact	0.0127	0.0192

As presented in Table 3-2 and Table 3-3 above, the baseline visibility contribution from individual Nelson Units as well as the cumulative contribution are significantly lower than the 0.5 dv screening threshold at both Class I areas. Therefore, Trinity concludes that none of the BART-eligible units at Nelson are causing or contributing to visibility impairment at any Class I area and thus no BART analysis is required.

Nonetheless, to comply with the Section 114 Request, Trinity conducted CALPUFF modeling to determine baseline visibility impairment attributable to Nelson Unit 4, Unit 6, and Auxiliary Boiler in two Class I Areas: Breton and Caney Creek. A summary of the existing visibility impairment for the original baseline period (2000-2004) at Unit 4 and Auxiliary Boiler is presented in Table 3-4 and Table 3-6. The existing visibility impairment for the refined baseline period (2012-2014) at Unit 6 is presented in Table 3-5.

Table 3-4. Baseline Visibility Impairment Attributable to Nelson Unit 4

Year[1]	98^{th} Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98^{th} Percentile Δdv SO_4	98^{th} Percentile Δdv NO_3	98^{th} Percentile Δdv PM_{10}	98^{th} Percentile Δdv NO_2
Caney Creek						
2001	0.032	0	0.000	0.030	0.002	0.000
2002	0.04	0	0.001	0.034	0.004	0.001
2003	0.037	0	0.000	0.033	0.001	0.002
Breton						
2001	0.036	0	0.000	0.032	0.002	0.001
2002	0.019	0	0.000	0.015	0.003	0.001
2003	0.036	0	0.000	0.034	0.002	0.000

[1] Meteorological data year modeled.

Table 3-5. Baseline Visibility Impairment Attributable to Nelson Unit 6

Year[1]	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek						
2001	0.405	5	0.273	0.129	0.004	0.000
2002	0.463	6	0.426	0.034	0.003	0.000
2003	0.368	4	0.338	0.026	0.004	0.000
Breton						
2001	0.459	7	0.427	0.028	0.003	0.000
2002	0.239	1	0.226	0.012	0.001	0.000
2003	0.493	7	0.445	0.046	0.002	0.000

[1] Meteorological data year modeled.

Table 3-6. Baseline Visibility Impairment Attributable to Nelson Aux Boiler

Year[1]	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek						
2001	0.008	0	0.005	0.003	0.000	0.000
2002	0.008	0	0.004	0.004	0.000	0.000
2003	0.006	0	0.005	0.001	0.000	0.000
Breton						
2001	0.008	0	0.008	0.000	0.000	0.000
2002	0.002	0	0.002	0.000	0.000	0.000
2003	0.01	0	0.009	0.001	0.000	0.000

[1] Meteorological data year modeled.

Based on the predicted visibility impacts based on CAMx modeling, the visibility improvement that could be achieved through the installation and operation of controls at each of the units would be negligible, such that the cost of emissions controls would not be justified.

4. SO_2 BART EVALUATION

BART FOR SO_2 - AUX BOILER & UNIT 4

The Nelson Auxiliary Boiler burns natural gas and fuel oil. Nelson Unit 4 burns primarily natural gas. The BART determination for the Auxiliary Boiler and Unit 4 would be no SO_2 controls. Table 3-4 and Table 3-6 demonstrate that Nelson Unit 4 and Auxiliary Boiler do not contribute one day of visibility impairment greater than 0.5 Δdv. Therefore, no controls would be considered BART for Unit 4 and Auxiliary Boiler. This conclusion is consistent for similar units in the proposed Arkansas federal implementation plan (FIP) and several other BART determinations.

IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES -UNIT 6

Nelson Unit 6 boiler burns primarily coal. Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from Nelson Unit 6, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 will further reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for Nelson Unit 6 are summarized in Table 4-1, and include: Dry Sorbent Injection (DSI) with ESP,[12] enhanced DSI with ESP, semi-dry scrubbing, wet scrubbing, and fuel switching to low sulfur coal.

Table 4-1. Available SO_2 Control Technologies for Nelson Unit 6

SO_2 Control Technologies
Dry Sorbent Injection (DSI) w/ESP
Enhanced DSI w/Fabric Filter
Dry / Semi-Dry Scrubbing, e.g., Spray Dryer Absorber (SDA)
Wet Scrubbing
Low Sulfur Coal

ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES - UNIT 6

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

Dry Sorbent Injection (DSI) and Enhanced DSI

Dry sorbent injection (DSI) involves the injection of a sorbent (e.g., Trona) into the exhaust gas stream where acid gases such as hydrogen chloride (HCl) and SO_2 react with and become entrained in the sorbent. The stream is then passed through a particulate control device to remove the sorbent and entrained SO_2. The process was

[12] ESP is already installed for Nelson Unit 6.

developed as a lower cost flue gas desulfurization (FGD) option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream instead of in a separate tower.

Enhanced DSI is decreasing the amount of sorbent injected into the exhaust gas stream and the installation of a fabric filter. Based on a site-specific study completed by Sargent & Lundy (S&L), DSI and enhanced DSI can result in between 30 and 80 percent reduction of SO_2.

Based on a site-specific study completed by S&L, DSI could technically achieve an SO_2 emission rate of 0.47 lb/MMBtu when coupled with the existing Nelson 6 ESP, and enhanced DSI could technically achieve an SO_2 emission rate of 0.19 lb/MMBtu when coupled with a new fabric filter.

Dry / Semi-Dry Scrubbing

There are various designs of dry or semi-dry scrubbing, or fuel gas desulfurization (FGD), systems, the most popular of which is the Spray Dryer Absorber (SDA) design. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter.

Based on a site-specific study completed by S&L, SDA could technically achieve an SO_2 emission rate of 0.06 lb/MMBtu at Nelson Unit 6.

Wet Scrubbing

Wet scrubbing, or wet flue gas desulfurization (WFGD), involves scrubbing the exhaust gas stream with slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an ESP to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. Similar to the chemistry illustrated above for spray dryer absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite and calcium sulfate. Based on a site-specific study completed by Sargent & Lundy, WFGD could technically achieve an SO_2 emission rate of 0.04 lb/MMBtu.

Fuel Switching

The coal burned at Nelson Unit 6 during the refined baseline period had an average sulfur content of 0.3% by weight.[13] Switching to a lower sulfur coal can reduce SO_2 emissions to approximately 0.6 lb/MMBtu.

RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS - UNIT 6

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing SO_2. Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

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[13] Based on 2012-2014 coal burn data for Unit 6.

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Estimated Control Efficiency (%)	Achievable Emission Rate (lb/MMBtu)[14]
Low Sulfur Coal	14	0.60
DSI w/ESP	32.6	0.47
Enhanced DSI w/ESP	72.8	0.19
Semi-Dry Scrubber (DFGD)	91.4	0.06
Wet Scrubber (WFGD)	94.3	0.04

EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS - UNIT 6

The fourth step in the BART analysis is the impact analysis where the impacts for those control options deemed feasible in Step 2 are evaluated. This analysis is typically conducted to demonstrate that a control technology that is more effective than another technology does not constitute BART. The BART guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

Cost of Compliance

The capital costs, annualized capital costs, and annual operating and maintenance costs for the considered control options were developed by Sargent & Lundy except for the low sulfur coal option, which is based on a cost premium of $0.50 per ton, which was provided by Entergy's fuel purchasing department. The details of the costs calculations are provided in Appendix A of this report.

The annual tons reduced used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was based on the average rate for the refined baseline period (2012-2014). Use of this refined baseline period provides a realistic depiction of anticipated annual emissions from the facility. The controlled annual emission rates were based on the lb/MMBtu levels believed to be achievable for the control technologies multiplied by the future annual heat input. The future annual heat input is based on the average actual heat input from CAMD for 2012 to 2014.

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 4-3 presents a summary of the cost effectiveness for each control option. The cost of switching to low sulfur coal is approximately $600/ton of SO_2 reduced. The cost effectiveness of the add-on controls are economically infeasible at more than $5,600/ton for DSI and enhanced DSI, $4,800/ton for dry scrubbing, and $4,700 for wet scrubbing.

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[14] Annual average.

As documented later in the report, the additional costs of the low sulfur coal and other add-on controls are not justified in light of the small improvement in visibility as compared to the high cost effectiveness values. As shown in Table 4-3, cost effectiveness are on the order of billions of dollars per deciview (based on the CAMx-predicted maximum impact as presented in the next section).

Table 4-3. Summary of Cost Effectiveness for SO_2 Controls at Unit 6

Case	Baseline SO_2 Emission Rate (tpy)[1]	Controlled Rate (lb/MMBtu)	Controlled Emission Rate (tpy)	SO_2 Reduced (tpy)	Total Annual Cost ($/yr)	Cost Effective-ness ($/ton)	Increment-al Cost Effective-ness ($/ton)	Cost Effective-ness ($B[2]/dv)
Refined Baseline	11,501.05	-	-	-	-	-	-	-
Low-Sulfur Coal		0.60	9,890.56	1,610.49	960,733	597	-	0.36
DSI		0.47	7,747.60	3,753.44	20,983,359	5,590	9,343	3.38
Enhanced DSI		0.19	3,132.01	8,369.04	46,958,504	5,611	5,628	3.40
Dry FGD		0.06	989.06	10,511.99	47,687,203	4,536	340	2.75
Wet FGD		0.04	659.37	10,841.68	47,842,583	4,413	471	2.67

[1] Annual average SO_2 baseline rate obtained from CAMD for years 2012-2014.
[2] Billions of dollars.

Energy Impacts and Non-Air Quality Impacts

The negative non-air quality environmental impacts are greater with wet scrubbing systems. Wet scrubbers require increased water use and generate large volumes of wastewater and solid waste/sludge that must be managed and/or treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. Moreover, if wet scrubbing produces calcium sulfite sludge, the sludge will be water-laden, and it must be stabilized for landfilling. Wet scrubbing systems require increased power requirements and increased reagent usage over dry scrubbers. Thus, from an overall environmental perspective, dry scrubbing is superior to wet scrubbing.

Remaining Useful Life

The remaining useful life of Unit 6 does not impact the annualized capital costs for either semi-dry scrubbing or wet scrubbing because the useful life of the unit is anticipated to be at least as long as the control equipment capital cost recovery period, which was set at 30 years, pursuant to the Section 114 Request.

EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS - UNIT 6

An impact analysis was conducted to assess the visibility improvement achieved by comparing the impacts associated with the baseline emission rates to the impacts associated with the maximum emission rates representative of each control option.

Table 4-4 summarizes the lb/hr emission rates that were modeled to reflect each control option. The NO_X and total PM_{10} emission rates were modeled at the refined baseline rates. The applicable NPS speciation spreadsheets were relied upon to determine emission rates for PM species.[15],[16],[17],[18], SO_4 emission rates were 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.[19]

Table 4-4. Emission Rates Modeled in CALPUFF to Reflect SO_2 Controls at Unit 6

Nelson Unit 6	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_x (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	EC (lb/hr)	SOA (lb/hr)	$PM_{10, total}$ (lb/hr)
Low sulfur coal	3,729.60	9.31	1,565.75	72.41	55.79	2.14	15.42	155.08
DSI w/ESP	2,921.52	16.44	1,565.75	16.62	16.01	0.62	105.38	155.08
Enhanced DSI	1,181.04	14.26	1,565.75	16.89	16.26	0.62	107.05	155.08
DFGD (SDA)	372.96	11.03	1,565.75	64.71	49.85	1.92	27.57	155.08
WFGD	248.64	10.79	1,565.75	52.68	55.80	2.14	33.66	155.08

Comparisons of the existing visibility impacts and the post-control visibility impacts based on fuel switching, DSI/enhanced DSI, dry scrubbing, and wet scrubbing, including the 98th percentile modeled visibility impact and the number of days with a modeled visibility impact greater than 0.5 Δdv, are provided in Table 4-5.

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[15] Low sulfur coal speciation is based on NPS Workbook, "Dry Bottom Boiler burning Pulverized Coal using ESP.xlsx", heating value of 8,579 btu/lb, 0.18% sulfur, 5.37% ash, and baseline PM_{10} emission rate of 155.1 lb/hr. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[16] DSI/Enhanced DSI speciation is based on NPS workbook, "Dry Bottom Boiler burning Pulverized Coal using FGD+ESP.xls". At the recommendation of Don Shepherd (NPS) via email (dated 10/13/15), the species calculation was modified to incorporate EPRI's F2 factor of 0.01, where 0.01 is the F2 factor for "Dry FGD and baghouse" obtained from EPRI Table 4-5. The following values were input into NPS workbook: heating value of 8,579 btu/lb, 0.3% sulfur, 5.37% ash, and baseline PM_{10} emission rate of 155.1 lb/hr. NPS: Ibid .

[17] DFGD speciation is based on NPS workbook, "Dry Bottom Boiler burning Pulverized Coal using FGD+ESP.xls", heating value of 8,579 btu/lb, 0.3% sulfur, 5.37% ash, and baseline PM_{10} emission rate of 155.1 lb/hr. NPS: Ibid.

[18] WFGD speciation is based on NPS workbook, "Wet Bottom Boiler burning Pulverized Coal using FGD+ESP.xls". NPS: Ibid.

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

Table 4-5. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Control for Unit 6 (2001-2003)

	BRET		CACR		CAMx Predicted Maximum Impacts (dv)	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	BRET	CACR
Refined Baseline	0.493	15	0.463	15	0.012	0.019
Low Sulfur Coal	0.336	11	0.299	5	-	-
Improvement over baseline	*0.157*	*4*	*0.164*	*10*	-	-
DSI + ESP	0.109	4	0.161	1	-	-
Improvement over baseline	*0.384*	*11*	*0.302*	*14*	-	-
Improvement over Low Sulfur Coal	*0.227*	*7*	*0.138*	*4*	-	-
Enhanced DSI + ESP	0.16	0	0.159	0	-	-
Improvement over baseline	*0.333*	*15*	*0.304*	*15*	-	-
Improvement over Low Sulfur Coal	*0.176*	*11*	*0.14*	*5*	-	-
Improvement over DSI + ESP	*-0.051*	*4*	*0.002*	*1*	-	-
DFGD System	0.102	0	0.108	1	-	-
Improvement over baseline	*0.391*	*15*	*0.355*	*14*	-	-
Improvement over Low Sulfur Coal	*0.234*	*11*	*0.191*	*4*	-	-
Improvement over DSI + ESP	*0.007*	*4*	*0.053*	*0*	-	-
Improvement over Enhanced DSI + ESP	*0.058*	*0*	*0.051*	*-1*	-	-
WFGD System	0.094	0	0.098	1	-	-
Improvement over baseline	*0.399*	*15*	*0.365*	*14*	-	-
Improvement over Low Sulfur Coal	*0.242*	*11*	*0.201*	*4*	-	-
Improvement over DSI + ESP	*0.015*	*4*	*0.063*	*0*	-	-
Improvement over Enhanced DSI + ESP	*0.066*	*0*	*0.061*	*-1*	-	-
Improvement over DFGD	*0.008*	*0*	*0.01*	*0*	-	-

Table 4-5 shows that, based on the visibility predictions from the CAMx model, the maximum possible visibility improvement to be obtained from controls cannot exceed the maximum baseline visibility impact of 0.019 Δdv at Breton. Therefore, no visibility improvement can reasonably be anticipated to result from the installation of controls. Furthermore, the cost of each of the add-on control options for Unit 6 are estimated as $3 billion or more per dv improvement.[20]

BART FOR SO_2 – UNIT 6

Based on the costs of the control options listed above and the negligible visibility impacts based on CAMx modeling, BART for Nelson Unit 6 would be no change from current operation.

[20] Estimation based on total annual cost of control divided by an assumed reduction in the baseline visibility impairment value calculated based on the reduction in SO_2 emissions.

5. PM_{10} BART EVALUATION

BART FOR PM_{10}

EPA's Approval and Promulgation of Implementation Plans, published March 12, 2012, determined that an ESP currently installed for coal-fired units similar to Nelson 6 is BART for PM_{10}:

> Since we have found that the visibility impact of the source due to PM emissions alone is so minimal such that the installation of any additional PM controls on the units would likely achieve very low emissions reductions, have minimal visibility benefits, and not be cost-effective, we are proposing to approve ADEQ's determination that PM BART for both the bituminous and subbituminous coal firing scenarios is the existing PM emission limit for [a similar coal-fired unit].[21]

As such, no further PM_{10} analysis has been conducted, and the BART determination for Nelson Unit 6 would be no fuel switches or add-on controls.

Section 3 of this report summarized the baseline visibility impairment attributable to Nelson Unit 4, Unit 6, and Auxiliary Boiler. Table 3-4 and Table 3-6 demonstrate that Unit 4 boiler and Auxiliary Boiler do not contribute to a single day of visibility impairment greater than 0.5 Δdv. Therefore, no controls would be considered BART for Unit 4 or Auxiliary Boiler. This conclusion is consistent with EPA's determinations in other states for similar units.

[21] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 FR 14658 (March 12, 2012).

APPENDIX A: CONTROL COST CALCULATIONS

Entergy®

NELSON UNIT 6

SO_2 BART CONTROL TECHNOLOGY SUMMARY

Addendum
April 14, 2016
Project 13027-003

Prepared by

Sargent & Lundy LLC

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1. PURPOSE

In response to Entergy's Regional Haze submittal on November 6, 2015, EPA submitted a request for additional information to Entergy on March16, 2016, which instructed Entergy to remove AFUDC from the BART cost estimates.

> *"The BART Guidelines require that cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual methodology, which uses the overnight cost method, does not allow for AFUDC to be assumed. Because AFUDC is not allowed under the Control Cost Manual approach, it should be removed from the Little Gypsy BART cost estimate, and any other BART cost estimates."*

We disagree that the *Control Cost Manual* describes an overnight approach to calculating capital costs. The *Control Cost Manual* does not once define or mention the overnight methodology as being the basis for estimating costs. Rather, the *Control Cost Manual* describes a constant dollar approach that annualizes all capital costs and O&M costs (on a constant-dollar basis) over the useful life of the project.

The term "total capital investment" is defined in the *Control Cost Manual* to include all costs required to purchase the equipment needed for the control system, the costs of labor and materials for installing that equipment, costs for site preparation and building, working capital, and off-site facilities, as well as indirect installation costs "such as engineering costs; construction and field expenses; contractor fees; start-up and performance test costs; and contingencies. AFUDC (or interest during construction) is an indirect capital cost that accounts for the time value of money associated with the distribution of construction cash flows over the construction period and should be included in capital cost estimates prepared in accordance with the methodology described in the *Control Cost Manual*.

Although specifically referenced in the *Control Cost Manual*, and more reflective of real-world project costs, Entergy has elected to exclude AFUDC in recognition of EPA's opinion that such costs should not be factored into five-factor Regional Haze BART analyses.

The cost included in the following table represent the cost of the evaluated SO_2 control technologies for Nelson Unit 6 excluding AFUDC (or interest during construction) based on the capital cost estimate previously developed.

Control Technology	Total Capital Investment with IDC	IDC Cost (Line 130)	Total Capital Investment without IDC
Dry Sorbent Injection	$104,556,900	$4,839,600	$99,717,300
Enhanced Dry Sorbent Injection	$306,150,600	$17,135,300	$289,015,300
Dry Flue Gas Desulfurization	$447,312,400	$52,466,600	$394,845,800
Wet Flue Gas Desulfurization	$491,917,000	$57,692,600	$434,224,400

2. REFERENCES

1. Entergy – Nelson Unit 6 – SO2 BART Control Technology Summary, Revision 0, November 6, 2015.
2. Entergy - Nelson Unit 6 – DSI Cost Estimate Basis Document, Revision 0, November 6, 2015.
3. Entergy - Nelson Unit 6 – Enhanced DSI Cost Estimate Basis Document, Revision 0, November 6, 2015.
4. Entergy - Nelson Unit 6 – Dry FGD Cost Estimate Basis Document, Revision 0, November 6, 2015.
5. Entergy - Nelson Unit 6 – Wet FGD Cost Estimate Basis Document, Revision 0, November 6, 2015.

NELSON UNIT 6

SO_2 BART CONTROL TECHNOLOGY SUMMARY

Revision 0
November 6, 2015
Project 13027-003

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1. PURPOSE

Entergy was requested by the U.S.EPA Region 6 to provide a Best Available Retrofit Technology (BART) evaluation for Nelson Unit 6 with respect to the Regional Haze Requirements. As part of this effort, Entergy requested that Sargent & Lundy (S&L) support this evaluation, with respect to sulfur dioxide (SO_2) emissions. The following technologies were identified as potential SO_2 control technologies for Nelson Unit 6:

- Dry Sorbent Injection (DSI)
- Enhanced DSI (DSI in conjunction with a new baghouse)
- Dry Flue Gas Desulfurization (FGD)
- Wet FGD

2. APPROACH

For each of these technologies S&L evaluated their feasibility and limitations, as well as estimating the total capital investment and annual operating and maintenance (O&M) costs for each technology. For a detailed description of the basis for developing capital and O&M costs see the attached Cost Estimate Scope and Technical Basis Documents for each of the evaluated technologies.

2.1 CAPITAL COST DEVELOPMENT

The capital cost estimates were developed to account for site-specific considerations and unit-specific operating data (e.g., fuel characteristics, temperature data, and current emission rates). Equipment costs for the major components of each technology were developed based on recent in-house equipment costs provided by equipment vendors for similar projects. Balance-of-plant costs for equipment tie-ins, ductwork, foundations, structural steel, piping, pumps, conduit, etc., and associated installation costs were estimated based on pricing for similar projects.

The capital cost estimates includes the following components which comprise the total cost the Owner will incur to install for each technology evaluated:

- Equipment Island Cost supplied by a qualified System Supplier including the main process equipment

- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation; allowances included as necessary
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Owner's Costs including internal labor, insurance, and initial reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner
- Escalation and Interest During Construction associated with the project duration for implementation of large air quality control technologies

The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of -20 to +50%.

2.2 O&M COST DEVELOPMENT

Variable O&M costs, such as reagent costs, water, auxiliary power, and others were developed based on estimated commodity consumption rates and unit pricing. It should be noted that the variable O&M costs rely heavily on the amount of SO_2 reduction estimated for each technology and the projected capacity factor. Fixed O&M costs were calculated using general cost factors for operating and supervisory labor, maintenance materials & labor, insurance and administration, as applicable.

3. SUMMARY OF SO_2 CONTROL TECHNOLOGIES

The following table summarizes the estimated capital and O&M costs for each of the potential SO_2 control technologies evaluated for Nelson Unit 6:

Control Technology	Controlled SO_2 Emission Rate[1]	Total Capital Investment	Annual Operating Cost[2]
Dry Sorbent Injection	0.47 lb/MMBtu	$104,556,900	$12,947,500 / year
Enhanced Dry Sorbent Injection	0.19 lb/MMBtu	$306,150,600	$23,667,800 / year
Dry Flue Gas Desulfurization	0.06 lb/MMBtu	$447,312,400	$15,868,000 / year
Wet Flue Gas Desulfurization	0.04 lb/MMBtu	$491,917,000	$12,850,000 / year

Note 1: DSI and Enhanced DSI controlled SO_2 emission rates are based on the maximum 30-day average SO_2 emission rate of 0.74 lb/MMBtu between 2012 and 2014.

Note 2: Annual first year operating costs (presented in $2015) represent the total variable and fixed O&M costs based on an average capacity factor of 62% between 2012 and 2014.

4. ATTACHMENTS

1. Entergy - Nelson Unit 6 – DSI Cost Estimate Basis Document.
2. Entergy - Nelson Unit 6 – Enhanced DSI Cost Estimate Basis Document.
3. Entergy - Nelson Unit 6 – Dry FGD Cost Estimate Basis Document.
4. Entergy - Nelson Unit 6 – Wet FGD Cost Estimate Basis Document.

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NELSON UNIT 6

DRY 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 dry 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) and the AACE Level 5 capital cost estimates.

2. TECHNOLOGY DESCRIPTION

Dry FGD technology was developed to reduce SO_2 emissions from low-sulfur coal; removal takes place in the absorber and the particulate collector (baghouse). The calcium in the lime slurry reacts with SO_2 in the flue gas to form waste solids (byproduct). The byproduct is predominately calcium sulfite ($CaSO_3$) with some calcium sulfate ($CaSO_4$). The chemical reactions are as follows:

$$Ca(OH)_2 + SO_2 + H_2O \Rightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O + {}^{3}/_{2}\, H_2O$$

$$CaSO_3 \cdot \tfrac{1}{2}H_2O + {}^{3}/_{2}\, H_2O + \tfrac{1}{2}O_2 \text{ (flue gas)} \Rightarrow CaSO_4 \cdot 2H_2O$$

SO_2 in the flue gas is removed by injection of fresh lime slurry (typically around 30 wt% solids) into the absorber tower. The lime slurry is atomized into fine droplets by injection with dual fluid spray nozzles or rotary atomizers. The flue gas fully dries the slurry solids in the absorber. A significant portion of the solids (byproduct) are recycled to improve the lime utilization.

The dry FGD process uses (powdered) hydrated lime ($Ca(OH)_2$) or (pebble) quicklime (CaO). Due to the large quantities of lime consumed, quicklime is typically more cost effective. Preparation of the fresh lime slurry involves slaking the quicklime. The slaking reaction is exothermic so safety systems are required. The lime slaking reaction is:

$$CaO + H_2O \Leftrightarrow Ca(OH)_2$$

Typically, the dry FGD outlet gas is designed to be 30°F above the adiabatic saturation point (approach to saturation temperature). The 30°F approach to saturation design margin ensures that water condensation will be avoided in the downstream equipment. With a 30°F approach to saturation, the downstream equipment materials of construction are carbon steel and corrosion is generally not a concern.

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 absorber vessels, baghouses, ductwork and booster ID fans.
  - Reagent storage, handling and preparation equipment; including storage silos and bins, lime slakers, slurry tanks, and conveying equipment.
  - Byproduct recycle and handling equipment; including storage silos, slurry tanks, and conveying equipment.

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 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 33593A provided in Attachment 1 represents the 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
- Bags and cages
- Operating labor
- Maintenance material and labor

The O&M Estimate and Cost Estimate 33593A 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 6 dry 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 94%.
- SO_2 Outlet Emission of 0.06 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 Dry FGD system on Nelson Unit 6. The dry FGD system supplier will provide all of the major components within the FGD Island including the absorber vessels, baghouse, and booster ID fans as well as equipment related to reagent handling and preparation and byproduct recycle and handling. 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. Dry FGD Island
   a. Reagent Preparation System:
      - Reagent Preparation Building, 60’ x 45’, including mat foundation and superstructure
      - Two lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
      - Two lime slurry transfer tanks

- Slurry transfer centrifugal pumps
- Two lime slurry storage tanks
- Slurry feed centrifugal pumps
- Sump pumps and agitators
- Equipment cost is based on recent pricing for a similar project.

b. Absorber Area:

- Two 65' diameter absorber vessels with access doors, including mat foundation and superstructure
- Penthouse enclosure for absorbers located on FGD Island (cost estimated separately)
- Two rotary atomizers and motors, one operating per absorber and one shared spare
- Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
- Heating and ventilation
- Vacuum piping
- Sump pumps and agitators
- Equipment cost is based on recent pricing for a similar project.

c. Baghouse Area

- New baghouse, including pulse jet cleaning system and all appurtenances
- Inlet and outlet plenum
- Baghouse hoppers with heaters
- Structural support steel
- Fill of bags and cages
- Equipment cost is based on recent pricing for a similar project.

d. Byproduct Recycle System

- Byproduct recycle building, 50' x 40', including mat foundation and superstructure
- One recycle silo with bin vent filter
- One recycle mix tank
- Two recycle slurry tanks, with slurry pumps
- Agitators for each tank
- Recycle ash pneumatic conveying system from baghouse hoppers to recycle silo
- Pneumatic pressure exhausters
- Equipment cost is based on recent pricing for a similar project.

2. Reagent Storage and Handling
   a. Lime storage silo:
      - One silo, 7-days storage, included as part of Reagent Preparation Building
      - 30' diameter and 60' height to top
      - Continuous level detection systems
      - Bin vent filter
      - Live bottom hopper outlets
      - Rotary airlock assemblies
      - Lime transfer systems:
        - Pressure pneumatic conveying system from lime storage silo to lime day bins
        - Pneumatic pressure blowers (3 x 100%)
        - One lot of pneumatic conveying piping located on a new elevated pipe rack

3. Byproduct Handling System
   a. Waste storage silo:
      - One silo, 3-days storage, including mat foundation and superstructure
      - 28' diameter and 32' height to top
      - Continuous level detection systems
      - Bin vent filter
      - Live bottom hopper outlets
      - Rotary airlock assemblies
      - Waste byproduct pneumatic transfer systems:
        - Vacuum pneumatic conveying system from baghouse to waste silo
        - Pneumatic vacuum exhausters
        - One lot of pneumatic conveying piping located on an elevated pipe rack
   b. Recycle storage silo:
      - One silo, 3-days storage, located on common mat foundation with Recycle Building
      - 50' diameter and 130' height to top
      - Continuous level detection systems
      - Live bottom hopper outlets
      - Rotary airlock assemblies
      - Recycle transfer systems:

- Pneumatic vacuum conveying system from baghouse to recycle silo
- Vacuum exhausters
- One lot of pneumatic conveying piping located on new flue gas duct support steel

4. Flue Gas Handling System
   a. ID fan outlets to absorber inlets ductwork and supports:
      - Two ID fan outlet ducts, combine to a single duct to carry flue gas to the new FGD area where the ductwork splits into two absorber inlets.
      - Carbon steel, ¼ in.
      - Velocity, 3,600 fpm
   b. Absorber outlets to baghouse inlets ductwork and supports:
      - Two separate ducts, leading from one absorber vessel to a dedicated baghouse.
      - Carbon steel, ¼ in.
      - Velocity, 3,600 fpm
   c. Baghouse outlets to Booster fans
      - Two baghouse outlet ducts, combine to a single duct, and then split into two booster fan inlets.
      - Carbon steel, ¼ in.
      - Velocity, 3,600 fpm
   d. 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
   e. Dampers and expansion joints
   f. 6" insulation and lagging
   g. Steel support structure and concrete mat foundations for all new flue gas ductwork

5. ID Booster Fans

a. Two, approximately 3,600 hp, axial booster fans sized to overcome pressure drop associated with dry FGD

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. 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. Lime slaking water storage tank, approximately 24-hour storage capacity
   d. Recycle make-up water tank, approximately 8-hour storage capacity
   e. Pipe Racks, including auxiliary steel and concrete foundations
   f. BOP Pumps
      - Three (3) x 50% by-product recycle water forwarding pumps to recycle slurry
      - Two (2) x 100% by-product recycle make-up water tank supply pumps
      - Two (2) x 100% lime slaking water pumps
      - Sump pumps
   g. Instrument Air System
      - Air compressors, 2 x 100%
      - IA dryers w/filters; 2 x 100%
      - Two air receivers
      - Instrument air piping
      - Heat-traced piping
   h. Service Air System
      - Air compressors, 2 x 100%
      - Two air receivers
   i. Eye wash and safety shower stations
   j. Field painting
   k. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD.

8. Demolition and Relocation

   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. Electrical

   a. Allowance of $27,300,000 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
      - 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. Controls System based on an estimated number of I/O points for the PLC based controls for the DFGD system:

       - Approximately 1,000 I/O points are required for each absorber unit DFGD system (including reagent preparation), for a total of 2,000 I/O points
       - Approximately 2,000 I/O points for the balance of plant for the DFGD 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. EPC Indirect Costs

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 lime 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 $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. 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 Dry 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 (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 $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 Dry 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, bag and cage costs, were provided by Entergy and are consistent with typical industry values. The reagent, bag and cage costs are based on recent in-house data from similar projects.

Table 3-1: Unit Pricing for Utilities

Unit Cost	Units	Value
Reagent (Lime)	$/ton	130.0
Make-up Water (High Quality)	$/1000 gal	1.25
Make-up Water (Low Quality)	$/1000 gal	0.50
Byproduct Waste Disposal	$/ton	7.50
Aux Power	$/MWh	40.00
Bag	$/bag	80.0
Cage	$/cage	30.0

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

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

Dry FGD System Parameters	Units	Value
Reagent Consumption	lb/hr	6,300
Byproduct Waste Production	lb/hr	12,700
Aux Power Consumption	kW	9,500
Make-up Water Consumption (High Quality)	gpm	40
Make-up Water Consumption (Low Quality)	gpm	620
No. of Bags in Baghouse		14,000
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	4,448,000
Byproduct Waste Disposal Cost	$/year	517,000
Aux Power Cost	$/year	4,128,000
Water Cost	$/year	235,000
Bags and Cages Replacement[3]	$/year	840,000
Total First Year Variable O&M Cost	**$/year**	**10,168,000**

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

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

Note 3: Bags will have to be replaced every 3 years and cages are replaced every 9 years.

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 dry 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 Dry FGD

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor	$/year	2,490,000
Maintenance Material	$/year	1,926,000
Maintenance Labor	$/year	1,284,000
Total First Year Fixed O&M Cost	**$/year**	**5,700,000**

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

5. ATTACHMENTS

1. Entergy Louisiana - Nelson Station - Unit 6 Dry FGD Addition Conceptual Cost Estimate, Sargent & Lundy Estimate No. 33593A.

ENTERGY LOUISIANA
NELSON STATION - UNIT 6
DRY 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.	33593A
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				366	27,145	27,145
	21.19.00	DISPOSAL				107	7,924	7,924
	21.20.00	BACKFILL			19,216	99	7,353	26,569
	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
	21.67.00	SURVEY	150,000					150,000
	21.99.00	CIVIL WORK, MISCELLANEOUS			390,000	4,400	326,513	716,513
		CIVIL WORK	150,000		2,719,196	35,528	3,710,395	6,579,591
22.00.00		CONCRETE						
	22.13.00	CONCRETE			1,238,493	38,560	2,445,481	3,683,974
	22.15.00	EMBEDMENT			45,353	832	46,542	91,894
	22.17.00	FORMWORK			14,115	1,242	107,231	121,346
	22.25.00	REINFORCING			203,258	3,927	195,041	398,298
		CONCRETE			1,501,218	44,561	2,794,294	4,295,512
23.00.00		STEEL						
	23.15.00	DUCTWORK			2,981,760	60,656	6,195,370	9,177,130
	23.17.00	GALLERY			732,580	4,010	262,546	995,126
	23.25.00	ROLLED SHAPE			5,735,465	40,663	3,641,404	9,376,869
		STEEL			9,449,805	105,329	10,099,320	19,549,125
24.00.00		ARCHITECTURAL						
	24.15.00	DOOR (INCL. FRAME & HARDWARE)			12,640	62	4,335	16,975
	24.33.00	PLUMBING FIXTURE			100,000	264	18,070	118,070
	24.35.00	PRE-ENGINEERED BUILDING	926,000		20,000	110	9,851	955,851
	24.37.00	ROOFING			33,750	282	16,932	50,682
	24.41.00	SIDING			507,113	5,182	459,045	966,158
	24.45.00	WINDOW (INCL. HARDWARE)			14,200	18	860	15,060
	24.99.00	ARCHITECTURAL, MISCELLANEOUS			2,000	35	1,970	3,970
		ARCHITECTURAL	926,000		689,703	5,952	511,063	2,126,766
27.00.00		PAINTING & COATING						
	27.17.00	PAINTING	150,000					150,000
		PAINTING & COATING	150,000					150,000
31.00.00		MECHANICAL EQUIPMENT						
	31.17.00	COMPRESSOR & ACCESSORIES		692,000		1,681	106,674	798,674
	31.25.00	CRANES & HOISTS		208,000		282	17,872	225,872
	31.27.00	DAMPERS & ACCESSORIES		620,000		2,693	170,902	790,902
	31.33.00	EXPANSION JOINT		462,500		5,088	519,689	982,189

Group	Phase	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
	31.35.00	FANS & ACCESSORIES (EXCL HVAC)		5,160,000		9,241	586,429	5,746,429
	31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM			79,000	352	22,175	101,175
	31.45.00	FGD EQUIPMENT		41,000,000			37,850,000	78,850,000
	31.51.00	MERCURY REMOVAL EQUIPMENT	100,000		138,000	2,011	116,000	354,000
	31.75.00	PUMP		297,200		510	32,393	329,593
	31.83.00	TANK	429,000					429,000
		MECHANICAL EQUIPMENT	529,000	48,439,700	217,000	21,858	39,422,135	88,607,835
33.00.00		MATERIAL HANDLING EQUIPMENT						
	33.13.00	BYPRODUCT HANDLING EQUIPMENT		4,140,000		25,303	1,691,804	5,831,804
	33.43.00	PNEUMATIC HANDLING SYSTEM		250,000		2,750	174,532	424,532
	33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS		10,000		66	4,189	14,189
		MATERIAL HANDLING EQUIPMENT		4,400,000		28,119	1,870,525	6,270,525
34.00.00		HVAC						
	34.31.00	DAMPER			5,500	154	10,662	16,162
	34.41.00	FAN			45,000	106	7,311	52,311
	34.53.00	UNIT HEATER			38,000	176	12,186	50,186
		HVAC			88,500	436	30,160	118,660
35.00.00		PIPING						
	35.13.01	SS 304, ABOVE GROUND, PROCESS AREA			28,160	944	80,816	108,976
	35.13.02	SS 316, ABOVE GROUND, PROCESS AREA			5,025	256	21,887	26,912
	35.13.10	CARBON STEEL, ABOVE GROUND, PROCESS AREA			101,775	6,900	590,424	692,199
	35.13.45	MISC. ABOVE GROUND, PROCESS AREA			30,000	550	47,068	77,068
	35.14.10	CARBON STEEL, STRAIGHT RUN			46,280	2,548	218,020	264,300
	35.35.00	PIPE SUPPORTS, HANGERS			99,082	4,536	388,153	487,235
	35.36.00	PIPE SUPPORTS, RACK			1,560	704	60,247	61,807
	35.45.00	VALVES			226,600	506	43,284	269,884
		PIPING			538,482	16,944	1,449,898	1,988,380
36.00.00		INSULATION						
	36.13.00	DUCT			1,723,293	65,624	3,686,771	5,410,064
	36.15.00	EQUIPMENT			328	11,155	626,694	627,022
	36.17.03	PIPE, MINERAL WOOL W/ALUMINUM JACKETING			71,333	2,454	137,867	209,199
		INSULATION			1,794,953	79,233	4,451,332	6,246,285
41.00.00		ELECTRICAL EQUIPMENT						
	41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS		9,500,000	4,700,000		13,100,000	27,300,000
		ELECTRICAL EQUIPMENT		9,500,000	4,700,000		13,100,000	27,300,000
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	7,255,000	62,339,700	21,698,856	337,959	77,439,123	168,732,679

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	77,439,123		337,959
Material	21,698,856		
Subcontract	7,255,000		
Process Equipment	62,339,700		
	168,732,679	**168,732,679**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	5,420,721		
91-2 Cost Due To OT 5-10's	10,520,400		
91-4 Per Diem	3,379,600		
91-5 Consumables	774,400		
91-6 Freight on Material	1,084,900		
91-8 Sales Tax	2,433,600		
91-9 Contractors G&A	12,253,900		
91-10 Contractors Profit	6,127,000		
	41,994,521	**210,727,200**	
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	22,937,700		
	41,587,700	**252,314,900**	
Escalation:			
96-1 Escalation on Material	3,291,100		
96-2 Escalation on Labor	20,396,700		
96-3 Escalation on Subcontract	1,357,900		
96-4 Escalation on Process Eq	7,134,800		
96-5 Escalation on Indirects	7,562,600		
	39,743,100	**292,058,000**	
Total EPC Cost		***292,058,000***	
Owner's Costs:			
99-1 Owner's Costs	20,185,200		
	20,185,200	**312,243,200**	
Third Party Services:			
100 CM Oversight	3,500,000		
101 Start-Up Oversight	420,000		
102 Owner's Engineer	4,000,000		
103 Performance Testing	175,000		
	8,095,000	**320,338,200**	
Project Contingency :			
110 Project Contingency	70,148,800		
	70,148,800	**390,487,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	4,358,800		
	4,358,800	**394,845,800**	
Interest During Construction:			
130 Interest During Constr.	52,466,600		
	52,466,600	**447,312,400**	
Total		***447,312,400***	

NELSON UNIT 6

DSI COST ESTIMATE BASIS DOCUMENT

Revision 0
November 6, 2015
Project 13027-003

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

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 estimate to install a new dry sorbent injection (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 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 the ESP) 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 the normal fly ash. These wastes will be collected in the ESP 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 fly ash 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.
- On-site disposal of DSI byproduct with existing ESP ash handling equipment. The byproduct will be collected in the existing ESP in conjunction with the fly ash from the unit and stored in a new concrete byproduct storage silo; no additional blending equipment is required. It was assumed that the existing ash handling equipment will be sufficient to accommodate the increase loading.
- The design injection rate for the equipment is based on 40% SO_2 removal from an uncontrolled SO_2 rate 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 typically requires a higher injection rate and is therefore a more conservative design basis for this system. Reagent injection will be at the APH outlet, upstream of the existing ESP.
    - Annual operating costs will be based on 40% 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 0.47 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.
- Increase in carbon consumption by 1 lb/mmacf to mitigate any impacts on mercury performance associated with ACI/DSI interference.
- 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 approximately 10 days storage

- Byproduct storage silo
- Quantity of mills
- Quantity of blower trains

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
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 33591A 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:

- Waste disposal (DSI waste + increased carbon + unsold fly ash)
- Loss of fly ash sales
- Reagent consumption (including increased carbon consumption)
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Estimate and Cost Estimate 33591A 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 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 40%.
- Permitted SO_2 Emission Limit of 0.47 lb SO_2/MMBtu.
- Annual capacity factor of 62%, based on historical operating data.
- Reagent injection at the APH outlet, upstream of the existing ESP.
- Reagent delivery by truck.
- Carbon silo storage time will be reduced, rather than adding additional storage silos to system.
- Compliance deadline of June 2021.

4.1 TOTAL INSTALLED CAPITAL INVESTMENT

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 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:
      - Six silos capable of storing approximately 10 days of sorbent, 2,100-tons storage total, including substructure
      - 14' diameter and 125' high, each
      - 350-tons working storage, each
      - Continuous level detection systems
      - Six bin vent filters for six silos
      - Live bottom hopper outlets
      - Rotary airlock assemblies
   c. Reagent conveying systems:
      - Two trains (2 x 100%)
      - 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 APH inlets
   - 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. Byproduct Handling
   a. One DSI by-product storage silo (approximately 7-day capacity) with bin vent filter, fluidizing system, and unloading conditioners (pin mixers)
   b. Water pumps and associated piping for unloading conditioners
   c. Compressed air system for air operated valves
   d. Storage silo substructure and superstructure
   e. Concrete foundations including piles for silos
   f. Continuous level detection system
   g. One lot pneumatic conveying piping located on an above grade pipe rack
   h. Two truck scales and substructure
   i. Cost estimate based on a recent budgetary proposal for similar project

3. 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 2 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.

4. Mechanical Work
   a. Allowance of $1,500,000 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

5. Demolition and Relocation

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

6. Electrical

   a. Allowance of $5,000,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects

7. Instrumentation

   a. Allowance of $600,000 is provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects

8. 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.

9. 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)

10. EPC Indirect Costs

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 $3,500,000.

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 $65,000.

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 $200,000.

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.

11. 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 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 $1,600,000.

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 $200,000.

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 $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 a DSI system 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 O&M costs. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent in-house pricing.

Table 1: Unit Pricing for Utilities

Unit Cost	Units	Value
Trona	$/ton	275.00
Carbon	$/ton	1,700
Low Quality Water	$/1000 gal	0.50
Waste Disposal	$/ton	7.50
Fly Ash Revenue	$/ton	8.00
Aux Power Cost	$/MWh	40.00

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	12,600
Increased Carbon Consumption	lb/hr	160
DSI Waste/Carbon/Unsold Fly Ash Rate	lb/hr	38,800
Aux Power Consumption	kW	1,000
Low Quality Water Consumption	gpm	3
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	9,410,000
Waste Disposal Cost	$/year	790,000
Increased Carbon Consumption Cost	$/year	739,000
Aux Power Cost	$/year	217,000
Low Quality Water Cost	$/year	500
Loss of Fly Ash Sales[3]	$/year	621,000
Total First Year Variable O&M Cost	**$/year**	**11,777,500**

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

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

Note 3: Assumes 100% of the station's fly ash was being sold on an annual basis for an average of approximately $8.00 per ton.

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). It was assumed that no additional operating personnel would be necessary for the DSI system; the system will be controlled through the existing control room.

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 1.6% of the total EPC cost.

Table 3 below summarizes the first year fixed O&M costs for the DSI system.

Table 3: Fixed O&M First Year Costs

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor	$/year	0
Maintenance Material	$/year	702,000
Maintenance Labor	$/year	468,000
Total First Year Fixed O&M Cost	**$/year**	**1,170,000**

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

5. ATTACHMENTS

1. Entergy Louisiana - Nelson Station - Unit 6 DSI System (40% SO_2 Reduction) EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 33591A.

ENTERGY LOUISIANA
NELSON STATION - UNIT 6
DSI SYSTEM (40% SO2 REDUCTION) 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.	33591A
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				118	20,386	20,386
	21.17.00	EXCAVATION				792	58,772	58,772
	21.39.00	STORM DRAINAGE UTILITIES			44,000	880	69,113	113,113
	21.41.00	EROSION AND SEDIMENTATION CONTROL			29,820	92	8,736	38,556
	21.53.00	PILING			244,860	3,267	348,199	593,059
	21.54.00	CAISSON			133,704	1,743	185,706	319,410
	21.99.00	CIVIL WORK, MISCELLANEOUS			156,000	1,760	130,605	286,605
		CIVIL WORK			608,384	8,653	821,518	1,429,902
22.00.00		CONCRETE						
	22.13.00	CONCRETE			326,140	10,920	692,527	1,018,667
		CONCRETE			326,140	10,920	692,527	1,018,667
23.00.00		STEEL						
	23.25.00	ROLLED SHAPE			92,160	634	56,745	148,905
		STEEL			92,160	634	56,745	148,905
24.00.00		ARCHITECTURAL						
	24.35.00	PRE-ENGINEERED BUILDING			10,000	110	9,851	19,851
	24.37.00	ROOFING			56,304	333	19,994	76,298
	24.41.00	SIDING			62,597	370	32,787	95,384
	24.99.00	ARCHITECTURAL, MISCELLANEOUS			35,900	1,023	78,592	114,492
		ARCHITECTURAL			164,801	1,836	141,224	306,025
26.00.00		MISCELLANEOUS STRUCTURAL ITEM						
	26.13.00	CONCRETE SILO	4,200,000	40,000		0		4,240,000
		MISCELLANEOUS STRUCTURAL ITEM	4,200,000	40,000		0		4,240,000
31.00.00		MECHANICAL EQUIPMENT						
	31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS	1,500,000	8,600,000			7,940,000	18,040,000
		MECHANICAL EQUIPMENT	1,500,000	8,600,000			7,940,000	18,040,000
33.00.00		MATERIAL HANDLING EQUIPMENT						
	33.13.00	BYPRODUCT HANDLING EQUIPMENT		6,335,000		53,793	3,817,655	10,152,655
	33.57.00	SCALE		182,000		440	27,925	209,925
		MATERIAL HANDLING EQUIPMENT		6,517,000		54,233	3,845,580	10,362,580
34.00.00		HVAC						
	34.37.00	DUST COLLECTOR	113,100					113,100
		HVAC	113,100					113,100
35.00.00		PIPING						
	35.14.10	CARBON STEEL, STRAIGHT RUN			49,600	759	64,954	114,554
		PIPING			49,600	759	64,954	114,554

Group	Phase	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
41.00.00		ELECTRICAL EQUIPMENT						
	41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS	5,000,000					5,000,000
		ELECTRICAL EQUIPMENT	5,000,000					5,000,000
44.00.00		CONTROL & INSTRUMENTATION						
	44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE	600,000					600,000
		CONTROL & INSTRUMENTATION	600,000					600,000
71.00.00		PROJECT INDIRECT						
	71.25.00	CONSULTANT, THIRD PARTY	150,000					150,000
		PROJECT INDIRECT	150,000					150,000
		TOTAL DIRECT	12,563,100	15,157,000	1,241,085	77,034	13,562,548	42,523,733

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	13,562,548		77,034
Material	1,241,085		
Subcontract	12,563,100		
Process Equipment	15,157,000		
	42,523,733	**42,523,733**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	949,367		
91-2 Cost Due To OT 5-10's	1,858,100		
91-4 Per Diem	770,300		
91-5 Consumables	135,600		
91-6 Freight on Material	62,100		
91-8 Sales Tax	678,300		
91-9 Contractors G&A	1,870,600		
91-10 Contractors Profit	935,300		
	7,259,667	**49,783,400**	
Indirect Costs:			
93-1 Engineering Services	3,500,000		
93-4 SU/S Parts/ Initial Fills	65,000		
93-5 Technical Field Advisors	200,000		
93-8 EPC Fee	5,354,800		
	9,119,800	**58,903,200**	
Escalation:			
96-1 Escalation on Material	239,700		
96-2 Escalation on Labor	4,627,200		
96-3 Escalation on Subcontract	3,054,400		
96-4 Escalation on Process Eq	2,209,200		
96-5 Escalation on Indirects	2,124,100		
	12,254,600	**71,157,800**	
Total EPC Cost		***71,157,800***	
Owner's Costs:			
99-1 Owner's Costs	4,712,300		
	4,712,300	**75,870,100**	
Third Party Services:			
100 CM Oversight	1,600,000		
101 Start-Up Oversight	200,000		
102 Owner's Engineer	2,750,000		
103 Performance Testing	175,000		
	4,725,000	**80,595,100**	
Project Contingency :			
110 Project Contingency	17,085,300		
	17,085,300	**97,680,400**	
Escalation Addition:			
120 Escalation on Lines 99-110	2,036,900		
	2,036,900	**99,717,300**	
Interest During Construction:			
130 Interest During Constr.	4,839,600		
	4,839,600	**104,556,900**	
Total		***104,556,900***	

Entergy®

NELSON UNIT 6

ENHANCED DSI COST ESTIMATE BASIS DOCUMENT

Revision 0
November 6, 2015
Project 13027-003

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

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

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

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. <u>Gypsum Byproduct Storage Area</u>

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. <u>Flue Gas Handling System</u>

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. <u>ID Booster Fans</u>

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. <u>Chimney</u>

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. <u>Civil Work</u>

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. <u>Mechanical Work</u>

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. Demolition and Relocation

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. Electrical

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. EPC Indirect Costs

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. 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 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: REFINED BASELINE PM SPECIATION CALCULATIONS

PM Speciation Calculations
Nelson Generating Plant

Nelson Refined Baseline (2012-2014)
Unit 4: Natural Gas

PM10 Speciation
Uncontrolled Natural Gas Boiler

Boiler	Heat Input (mmBtu/hr)	Filterable PM (AP-42) (lb/hr)	Condensible PM (AP-42) (lb/hr)	Total PM (lb/hr)	*Condensible* SO4 (lb/hr)	PMC (lb/hr)	PMF (lb/hr)	*Filterable* EC (lb/hr)	*Condensible* SOA (lb/hr)
Nelson Unit 4	4,314	8.04	24.11	32.14	1.29	0	0	8.04	22.82

Notes:
1. EC Basis: "All filterable PM will be considered elemental carbon". National Park Service, PM Speciation for Natural Gas Fired Combustion Turbines: http://www.nature.nps.gov/air/permits/ect/ectGasFiredCT.cfm
2. SO4 Basis: "One-third of estimated SO2 emissions would be carved-out and adjusted for differences in molecular weight to represent SO4 emissions." Ibid.
3. SOA Basis: "Estimate the organic component of the condensibles (expressed as Organic Carbon) by subtracting the SO4 from the condensible fraction. Ibid.
4. Filterable PM emission factor (1.9 lb/MMscf) and Condensible PM emission factor (5.7 lb/MMscf) was obtained from AP-42, Table 1.4-2.
   Emission factors were converted from lb/MMscf to lb/Mmbtu using heat value 1,020 Mmbtu/MMscf.
5. All condensible particulate assumed to be organic carbon.

PM Speciation Calculations
Nelson Generating Plant

Entergy Nelson, Unit 6 Boiler (Coal-Fired)
Refined Baseline 2012-2014

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

assumes heating value of **8,579** Btu/lb and a sulfur content of **0.30** % and an ash content of **5.37** % and a heat input of **6,461** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0269	0.0169	0.0094	0.6	0.0075	0.0072	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.462	**0.290**	0.161	0.6	**0.129**	0.124	1	0.005	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	62.8%	34.9%	0.6	27.9%	26.9%	1	1.0%	10	37.2%	29.7%	SO4	3*f(RH)	7.4%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle		
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.	
PC-DB	**155.1**	97.4	54.1	0.6	43.3	41.7	1	1.6	10	57.6	46.1	SO4	3	11.5	SOA	4	
		Weighted Extinction		*32.5*			*41.7*		*16.0*				*138.3*			*46.1*	*1.8*

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR		**10.38 lb/hr**	(SO_4)

Redistribute remainder of total PM_{10}:		144.7 lb/hr	
Coarse	49.7%	**71.88 lb/hr**	(PMC)
Fine Soil	38.3%	**55.38 lb/hr**	(PMF)
Fine EC	1.5%	**2.13 lb/hr**	(EC)
CPM OR	10.6%	**15.31 lb/hr**	(SOA)

PM Speciation Calculations
Nelson Generating Plant

Entergy Nelson
Unit 6 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012			**Page Reference**
TSAR		= Total sulfuric acid release	4-11 (Eqn 4-10)
		= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
		= 90,970.01 lb/year	In '01'-03, FGC was upstream of the APH (now it is downstream)
where:			
EM_{Comb}	=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=	K * F1 * E2	
	=	92,007.09 lb/year	calc
where	K =	Units conversion factor	4-1
	=	3063 lb H_2SO_4/ton SO_2	4-1
	F1 =	Fuel Impact Factor	4-1
	=	0.00111 *unitless*	4-6 (Table 4-1 for W. Bituminous, Dry bottom boiler)
	E2 =	SO_2 emission rate	4-1
	=	27,061.47 tons/yr (max. day during '12-'14)	Entergy data
EM_{SCR}	=	H_2SO_4 manufactured from SCR	4-7
	=	0 lb/year	SCR is not present
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	4-9 (Eqn 4-7)
	=	$EM_{FGC\_beforeAPH}$ *$EM_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_s * F3_{FGC}$	4-9 (Eqn 4-7)
	=	258,957.47 lb/year	calc
where	K_e =	Conversion factor	4-9
	=	3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B =	Coal burn	4-9
	=	32.97 TBtu/yr (average for '12-'14)	Entergy data
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	1 *unitless*	default value = 0.8 (Entergy operates the FGC continuously)
	I_s =	SO_3 injection rate	4-9
	=	12.2 ppmv at 6% O_2, wet	default value = 7, but: 15 ppmv @ 2.5% O2 per Entergy data
	$F3_{FGC}$ =	Technology impact factor	4-9
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR is not present
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14
	=	$NH3_{FGC\_beforeAPH}$ *$NH3_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_{NH3}$	4-14 (Eqn 4-14)
	=	0 lb/year	calc
where	K_e =	*see above*	*see above*
	B =	*see above*	*see above*
	f_e =	*see above*	*see above*
	I_{NH3} =	NH_3 injection for dual FGC	4-14
	=	0 ppmv at 6% O_2, wet	Entergy: no ammonia injection
$F2_X$	=	Technology impact factors for processes downstream of the APH (sum of all that apply)	4-12
	=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)

PM Speciation Calculations
Nelson Generating Plant

Nelson, Auxiliary Boiler (#2 oil with 0.5% sulfur)
Refined Baseline (2012-2014)

Controlled PM10 Speciation from AP-42 Tables 1.3-2 & 1.3-4
Uncontrolled Utility Residual Oil Boiler

Assumes firing of # 2 oil with a sulfur content of 0.50 %S; therefore, A 0.93 f(RH) = 1
Assumes heating value of 140,476 Btu/Gal and a heat input of 206 mmBtu/hr

Uncontrolled PM10 Emissions (**Bold** Values from Tables 1.3-2 and 1.3-4.)

Boiler Type	Total PM10 (lb/mGal)	Filterable (lb/mGal)	Coarse (lb/mGal)	Ext. Coef.	Fine (lb/mGal)	Fine Soil (lb/mGal)	Ext. Coef.	Fine EC (lb/mGal)	Ext. Coef.	Condensible (lb/mGal)	CPM IOR (lb/mGal)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mGal)	Particle Type	Particle Ext.Coef.
Utility	6.99	**5.49**	1.49	0.6	**4.00**	3.70	1	0.30	10	**1.5**	1.28	SO4	3*f(RH)	0.23	SOA	4

Uncontrolled PM10 Emissions

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
Utility	100%	78.5%	21.3%	0.6	57.2%	53.0%	1	4.2%	10	21.5%	18.2%	SO4	3*f(RH)	3.2%	SOA	4

Uncontrolled PM10 Emissions

Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/mmBtu)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
Utility	0.05	0.04	0.01	0.6	0.03	0.03	1	0.002	10	0.01	0.01	SO4	3*f(RH)	0.002	SOA	4

If you are given Total PM10 emissions in lb/hr:

Uncontrolled PM10 Emissions (**Bold** Value is **Input** by user.)

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.	
Utility	**3.5**	2.7	0.7	0.6	2.0	1.8	1	0.1	10	0.7	0.6	SO4	3	0.1	SOA	4	
		Weighted Extinction		0.4			1.8		1.5				1.9			0.4	1.8

Coarse	21.3%	Coarse	0.7	(PMC)
Fine Soil	53.0%	Fine Soil	1.8	(PMF)
Fine EC	4.2%	Fine EC	0.1	(EC)
CPM IOR	18.2%	CPM IOR	0.6	(SO4)
CPM OR	3.2%	CPM OR	0.1	(SOA)
	100.0%		3.5	

Notes:
PM Speciation workbook was obtained from the National Park Service:
http://www.nature.nps.gov/air/permits/ect/ectOilFiredBoiler.cfm

APPENDIX C: POST CONTROL PM SPECIATION CALCULATIONS

PM Speciation Calculations
Nelson Generating Plant

Nelson - Unit 6 Boiler
Post-Control: Fuel switch to Low Sulfur Coal

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

assumes heating value of **8,579** Btu/lb and a sulfur content of **0.182** % and an ash content of **5.37** % and a heat input of **6,216** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)														
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0269	0.0169	0.0094	0.6	0.0075	0.0072	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)														
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.462	**0.290**	0.161	0.6	**0.129**	0.124	1	0.005	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions														
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	62.8%	34.9%	0.6	27.9%	26.9%	1	1.0%	10	37.2%	29.7%	SO4	3*f(RH)	7.4%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.	
PC-DB	**155.1**	97.4	54.1	0.6	43.3	41.7	1	1.6	10	57.6	46.1	SO4	3	11.5	SOA	4	
		Weighted Extinction		*32.5*			*41.7*		*16.0*				*138.3*			*46.1*	*1.8*

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR	**9.31**	**lb/hr**	(SO_4)

Redistribute remainder of total PM_{10}: 145.8 lb/hr

Coarse	49.7%	**72.41**	**lb/hr**	(PMC)
Fine Soil	38.3%	**55.79**	**lb/hr**	(PMF)
Fine EC	1.5%	**2.14**	**lb/hr**	(EC)
CPM OR	10.6%	**15.42**	**lb/hr**	(SOA)

PM Speciation Calculations
Nelson Generating Plant

Entergy Nelson
Unit 6 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012			**Page Reference**
TSAR	=	Total sulfuric acid release	4-11 (Eqn 4-10)
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
	=	81,517.76 lb/year	In '01'-03, FGC was upstream of the APH (now it is downstream)
where:			
EM_{Comb}	=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=	K * F1 * E2	
	=	55,540.06 lb/year	calc
where	K =	Units conversion factor	4-1
	=	3063 lb H_2SO_4/ton SO_2	4-1
	F1 =	Fuel Impact Factor	4-1
	=	0.00111 *unitless*	4-6 (Table 4-1 for W. Bituminous, Dry bottom boiler)
	E2 =	SO_2 emission rate	4-1
	=	16,335.65 tons/yr (controlled SO2 rate)	Entergy data
EM_{SCR}	=	H_2SO_4 manufactured from SCR	4-7
	=	0 lb/year	SCR is not present
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	4-9 (Eqn 4-7)
	=	$EM_{FGC\_beforeAPH}$ *$EM_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_s * F3_{FGC}$	4-9 (Eqn 4-7)
	=	258,957.47 lb/year	calc
where	K_e =	Conversion factor	4-9
	=	3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B =	Coal burn	4-9
	=	32.97 TBtu/yr (average for '12-'14)	Entergy data
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	1 *unitless*	default value = 0.8 (Entergy operates the FGC continuously)
	I_s =	SO_3 injection rate	4-9
	=	12.2 ppmv at 6% O_2, wet	default value = 7, but: 15 ppmv @ 2.5% O2 per Entergy data
	$F3_{FGC}$ =	Technology impact factor	4-9
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR is not present
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14
	=	$NH3_{FGC\_beforeAPH}$ *$NH3_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_{NH3}$	4-14 (Eqn 4-14)
	=	0 lb/year	calc
where	K_e =	*see above*	*see above*
	B =	*see above*	*see above*
	f_e =	*see above*	*see above*
	I_{NH3} =	NH_3 injection for dual FGC	4-14
	=	0 ppmv at 6% O_2, wet	Entergy: no ammonia injection
$F2_X$	=	Technology impact factors for processes downstream of the APH (sum of all that apply)	4-12
	=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM10 emission rate is based on maximum daily HI from 2012-2014 CAMD and stack test factor.

PM Speciation Calculations
Nelson Generating Plant

Nelson - Unit 6 Boiler
Post-Control: DSI+ESP

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+ESP for Emissions control
assumes heating value of **8,579** Btu/lb and a sulfur content of **0.30** % and an ash content of **5.37** % and a heat input **6,216** mmBtu/hr and FGD penetration factor = **0.01**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0263	0.0063	0.0031	0.6	0.0031	0.0030	1	0.00012	10	**0.020**	0.000	SO4	3*f(RH)	0.020	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.451	**0.107**	0.054	0.6	**0.054**	0.052	1	0.0020	10	0.343	0.003	SO4	3*f(RH)	0.340	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	23.8%	11.9%	0.6	11.9%	11.5%	1	0.4%	10	76.2%	0.6%	SO4	3*f(RH)	75.6%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**155.1**	37.0	18.5	0.6	18.5	17.8	1	0.7	10	118.1	0.9	SO4	3*f(RH)	117.2	SOA	4

If you are given Total PM10 emissions in lb/mmBtu:
Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR		**16.44 lb/hr**	(SO_4)

Redistribute remainder of total PM_{10}: 138.6 lb/hr

Coarse	12.0%	**16.62 lb/hr**	(PMC)
Fine Soil	11.5%	**16.01 lb/hr**	(PMF)
Fine EC	0.4%	**0.62 lb/hr**	(EC)
CPM OR	76.0%	**105.38 lb/hr**	(SOA)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012 — **Page Reference**

TSAR = Total sulfuric acid (H_2SO_4) release, lbs/yr — 4-11 (Eqn 4-10)

$= \{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$

= 120,034.03 lb/year

where:

EM_{Comb} = H_2SO_4 manufactured from combustion, lbs/yr — 4-1 (Eqn 4-1)

= K * F1 * E2

= 74,470.38 lb/year

where K = Units conversion factor

= 3063 lb H_2SO_4/ton SO_2

F1 = Fuel Impact Factor (PRB coal, all boiler types)

= 0.0019 *unitless* — 4-6 (Table 4-1)

E2 = SO_2 emission rate, tons/yr

= 12,796.26 tons/yr (controlled SO2 rate) — S&L

PM Speciation Calculations
Nelson Generating Plant

Nelson Unit 6 (DSI + ESP)

EPRI (Continued)

EM_{SCR}	=	H_2SO_4 manufactured from SCR	4-7 (Eqn 4-6)
	=	0 lb/year	SCR is not present
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	4-9 (Eqn 4-7)
	=	$EM_{FGC\_beforeAPH}$ *$EM_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_s * F3_{FGC}$	
	=	258,957 lb/year	FGC is not present
where K_e	=	Conversion factor	4-9
	=	3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B	=	Coal burn	4-9
	=	32.97 TBtu/yr (average for '12-'14)	Entergy data
f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	1 *unitless*	default value = 0.8 (Entergy operates the FGC continuously)
I_s	=	SO_3 injection rate	4-9
	=	12.2 ppmv at 6% O_2, wet	default value = 7, but: 15
$F3_{FGC}$	=	Technology impact factor	4-9 ppmv @ 2.5% O2 per Entergy data
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR is not present
$F2_{APH}$	=	Technology impact factor for APH; only apply if [(EM_{Comb} + EM_{SCR} + $EM_{FGC\_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC\_beforeAPH}$)] is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14 (FGC not present)
	=	$NH3_{FGC\_beforeAPH}$ *$NH3_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_{NH3}$	
	=	0 lb/year No FGC is present	
$F2_X$	=	Technology impact factors for processes downstream of the APH (sum of all that apply)	4-12
	=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
	=	0.01 for dry FGD and baghouse	
	=	0.73 sum of all factors	
$TSAR_{ALKINJ}$	=	($TSAR_{Comb+SCR+FGC}$) * $F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$	=	120,034.03 lb/year	
$F3_{ALKINJ}$	=	0.2 expected fractional reduction in SO3, default is 0.2.	3-9
	=	24006.805 lb/year	
Total TSAR	=	($TSAR_{Comb+SCR+FGC}$) + ($TSAR_{ALKINJ}$)	
	=	144,040.83 lb/year	

Notes:
1. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
2. FGD penetration factor of 0.01 (EPRI, Table 4-4) was incorporated into the NPS workbook for DSI. TSAR for alkali injection was incorporated into the EPRI SO4 calculation. Per Don Shepherd at NPS (email dated 10/13/15).
3. PM10 emission rate is based on maximum daily HI from 2012-2014 CAMD and stack test factor.

PM Speciation Calculations
Nelson Generating Plant

Nelson - Unit 6 Boiler
Post-Control: Enhanced DSI+ESP

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+ESP for Emissions control
assumes heating value of **8,579** Btu/lb and a sulfur content of **0.30** % and an ash content of **5.37** % and a heat input **6,216** mmBtu/hr and FGD penetration factor = **0.01**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)																
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0263	0.0063	0.0031	0.6	0.0031	0.0030	1	0.00012	10	**0.020**	0.000	SO4	3*f(RH)	0.020	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.451	**0.107**	0.054	0.6	**0.054**	0.052	1	0.0020	10	0.343	0.003	SO4	3*f(RH)	0.340	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	23.8%	11.9%	0.6	11.9%	11.5%	1	0.4%	10	76.2%	0.6%	SO4	3*f(RH)	75.6%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**155.1**	37.0	18.5	0.6	18.5	17.8	1	0.7	10	118.1	0.9	SO4	3*f(RH)	117.2	SOA	4

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR		**14.26 lb/hr**	(SO_4)
Redistribute remainder of total PM_{10}:		140.8 lb/hr	
Coarse	12.0%	**16.89 lb/hr**	(PMC)
Fine Soil	11.5%	**16.26 lb/hr**	(PMF)
Fine EC	0.4%	**0.62 lb/hr**	(EC)
CPM OR	76.0%	**107.05 lb/hr**	(SOA)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012 — **Page Reference**

TSAR = Total sulfuric acid (H_2SO_4) release, lbs/yr — 4-11 (Eqn 4-10)
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$
= 104,062.51 lb/year

where:

EM_{Comb} = H_2SO_4 manufactured from combustion, lbs/yr — 4-1 (Eqn 4-1)
= K * F1 * E2
= 30,105.05 lb/year

where K = Units conversion factor
= 3063 lb H_2SO_4/ton SO_2

F1 = Fuel Impact Factor (PRB coal, all boiler types)
= 0.0019 *unitless* — 4-6 (Table 4-1)

E2 = SO_2 emission rate, tons/yr
= 5,172.96 tons/yr (controlled SO2 rate) — S&L

PM Speciation Calculations
Nelson Generating Plant

Nelson Unit 6 (Enhanced DSI + ESP)

EPRI (Continued)

EM_{SCR}	=	H_2SO_4 manufactured from SCR	4-7 (Eqn 4-6)
	=	0 lb/year	SCR is not present
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	4-9 (Eqn 4-7)
	=	$EM_{FGC\_beforeAPH}$ *$EM_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_s * F3_{FGC}$	
	=	258,957 lb/year	FGC is not present
where K_e	=	Conversion factor	4-9
	=	3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B	=	Coal burn	4-9
	=	32.97 TBtu/yr (average for '12-'14)	Entergy data
f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	1 *unitless*	default value = 0.8 (Entergy operates the FGC continuously)
I_s	=	SO_3 injection rate	4-9
	=	12.2 ppmv at 6% O_2, wet	default value = 7, but: 15 O2 per Entergy data
$F3_{FGC}$	=	Technology impact factor	4-9
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR is not present
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14 (FGC not present)
	=	$NH3_{FGC\_beforeAPH}$ *$NH3_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_{NH3}$	
	=	0 lb/year No FGC is present	
$F2_X$	=	Technology impact factors for processes downstream of the APH (sum of all that apply)	4-12
	=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
	=	0.01 for dry FGD and baghouse	
	=	0.73 sum of all factors	
$TSAR_{ALKINJ}$	=	$(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$	=	104,062.51 lb/year	
$F3_{ALKINJ}$	=	0.2 expected fractional reduction in SO3, default is 0.2.	3-9
	=	20812.501 lb/year	
Total TSAR	=	$(TSAR_{Comb+SCR+FGC}) + (TSAR_{ALKINJ})$	
	=	124,875.01 lb/year	

Notes:
1. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
2. FGD penetration factor of 0.01 (EPRI, Table 4-4) was incorporated into the NPS workbook for DSI. TSAR for alkali injection was incorporated into the EPRI SO4 calculation. Per Don Shepherd at NPS (email dated 10/13/15).
3. PM10 emission rate is based on maximum daily HI from 2012-2014 CAMD and stack test factor.

PM Speciation Calculations
Nelson Generating Plant

Nelson - Unit 6 Boiler
Post-Control: DFGD+ESP

Dry Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

assumes heating value of **8578.63** Btu/lb and a sulfur content of **0.30** % and an ash content c **5.37** % and a heat input **6,216** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)																	
Boiler	Total PM10		Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.		Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)		(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.		(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0369		0.0169	0.0094	0.6	0.0075	0.0072	1	0.0003	10		**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)																	
Boiler	Total PM10		Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.		Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)		(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.		(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.633		**0.290**	0.161	0.6	**0.129**	0.124	1	0.005	10		0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions																	
Boiler	Total PM10		Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.		Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)		(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.		(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%		45.8%	25.4%	0.6	20.4%	19.6%	1	0.8%	10		54.2%	43.4%	SO4	3*f(RH)	10.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)																		
Boiler	Total PM10		Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.		Condensible	CPM IOR	Particle		CPM OR	Particle		
Type	(lb/hr)		(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.		(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.	
PC-DB	**155.1**		71.0	39.5	0.6	31.6	30.4	1	1.2	10		84.0	67.2	SO4	3	16.8	SOA	4	
			Weighted Extinction		23.7			30.4		11.7					201.7			67.2	2.2

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR		**11.03 lb/hr**	(SO_4)

Redistribute remainder of total PM_{10}: 144.0 lb/hr

Coarse	44.9%	**64.71 lb/hr**	(PMC)
Fine Soil	34.6%	**49.85 lb/hr**	(PMF)
Fine EC	1.3%	**1.92 lb/hr**	(EC)
CPM OR	19.1%	**27.57 lb/hr**	(SOA)

PM Speciation Calculations
Nelson Generating Plant

Entergy Nelson
Unit 6 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012 — **Page Reference**

				Page Reference
TSAR		=	Total sulfuric acid release	4-11 (Eqn 4-10)
		=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
		=	96,647.16 lb/year	In '01'-03, FGC was upstream of the APH (now it is downstream)
where:				
EM_{Comb}		=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
		=	K * F1 * E2	
		=	9,506.86 lb/year	calc
where	K	=	Units conversion factor	4-1
		=	3063 lb H_2SO_4/ton SO_2	4-1
	F1	=	Fuel Impact Factor	4-1
		=	0.0019 *unitless*	4-6 (Table 4-1 for W. Bituminous, Dry bottom boiler)
	E2	=	SO_2 emission rate	4-1
		=	1,633.56 tons/yr (controlled SO2 rate)	Entergy data
EM_{SCR}		=	H_2SO_4 manufactured from SCR	4-7
		=	0 lb/year	SCR is not present
EM_{FGC}		=	H_2SO_4 manufactured from flue gas conditioning	4-9 (Eqn 4-7)
		=	$EM_{FGC\_beforeAPH}$ *$EM_{FGC\_afterAPH}$ = 0*	
		=	$K_e * B * f_e * I_s * F3_{FGC}$	4-9 (Eqn 4-7)
		=	258,957.47 lb/year	calc
where	K_e	=	Conversion factor	4-9
		=	3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B	=	Coal burn	4-9
		=	32.97 TBtu/yr (average for '12-'14)	Entergy data
	f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
		=	1 *unitless*	default value = 0.8 (Entergy operates the FGC continuously)
	I_s	=	SO_3 injection rate	4-9
		=	12.2 ppmv at 6% O_2, wet	default value = 7, but: 15 ppmv @ 2.5% O2 per Entergy data
	$F3_{FGC}$	=	Technology impact factor	4-9
		=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$		=	Ammonia slip produced from SCR/SNCR	4-13
		=	0 lb/year	SCR is not present
$F2_{APH}$		=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
		=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$		=	Ammonia produced from FGC	4-14
		=	$NH3_{FGC\_beforeAPH}$ *$NH3_{FGC\_afterAPH}$ = 0*	
		=	$K_e * B * f_e * I_{NH3}$	4-14 (Eqn 4-14)
		=	0 lb/year	calc
where	K_e	=	*see above*	*see above*
	B	=	*see above*	*see above*
	f_e	=	*see above*	*see above*
	I_{NH3}	=	NH_3 injection for dual FGC	4-14
		=	0 ppmv at 6% O_2, wet	Entergy: no ammonia injection
$F2_X$		=	Technology impact factors for processes downstream of the APH (sum of all that apply)	4-12
		=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
		=	0.01 for dry FGD and baghouse	4-22 (Table 4-5 for Dry FGD and baghouse)
		=	0.73 total F2 factors	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM10 emission rate is based on maximum daily HI from 2012-2014 CAMD and stack test factor.
4. Nelson 6 has an existing ESP (per Permit 05220-00014-V2.pdf)

PM Speciation Calculations
Nelson Generating Plant

Nelson - Unit 6 Boiler
Post-Control: WFGD+ESP

Wet Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

assumes heating value of **8578.63** Btu/lb and a sulfur content of **0.30** % and an ash content **5.37** % and a heat ir **6,216** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-WB	0.0331	0.0131	0.0063	0.6	0.0069	0.0066	1	0.0003	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-7.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-WB	0.569	**0.226**	0.107	0.6	**0.118**	0.114	1	0.004	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-WB	100%	39.7%	18.9%	0.6	20.8%	20.0%	1	0.8%	10	60.3%	48.3%	SO4	3*f(RH)	12.1%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle		
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.	
PC-WB	**155.1**	61.5	29.3	0.6	32.2	31.0	1	1.2	10	93.6	74.9	SO4	3	18.7	SOA	4	
		Weighted Extinction		17.6			31.0		11.9				224.6			74.9	2.3

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR		**10.79 lb/hr**	(SO_4)

Redistribute remainder of total PM_{10}: 144.3 lb/hr

Coarse	36.5%	**52.68 lb/hr**	(PMC)
Fine Soil	38.7%	**55.80 lb/hr**	(PMF)
Fine EC	1.5%	**2.14 lb/hr**	(EC)
CPM OR	23.3%	**33.66 lb/hr**	(SOA)

PM Speciation Calculations
Nelson Generating Plant

Entergy Nelson
Unit 6 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012			**Page Reference**
TSAR	=	Total sulfuric acid release	4-11 (Eqn 4-10)
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
	=	94,557.65 lb/year	In '01'-03, FGC was upstream of the APH (now it is downstream)
where:			
EM_{Comb}	=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=	K * F1 * E2	
	=	3,702.67 lb/year	calc
where	K =	Units conversion factor	4-1
	=	3063 lb H_2SO_4/ton SO_2	4-1
	F1 =	Fuel Impact Factor	4-1
	=	0.00111 *unitless*	4-6 (Table 4-1 for W. Bituminous, Dry bottom boiler)
	E2 =	SO_2 emission rate	4-1
	=	1,089.04 tons/yr (controlled SO2 rate)	Entergy data
EM_{SCR}	=	H_2SO_4 manufactured from SCR	4-7
	=	0 lb/year	SCR is not present
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	4-9 (Eqn 4-7)
	=	$EM_{FGC\_beforeAPH}$ *$EM_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_s * F3_{FGC}$	4-9 (Eqn 4-7)
	=	258,957.47 lb/year	calc
where	K_e =	Conversion factor	4-9
	=	3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B =	Coal burn	4-9
	=	32.97 TBtu/yr (average for '12-'14)	Entergy data
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	1 *unitless*	default value = 0.8 (Entergy operates the FGC continuously)
	I_s =	SO_3 injection rate	4-9
	=	12.2 ppmv at 6% O_2, wet	default value = 7, but: 15 ppmv @ 2.5% O2 per Entergy dat
	$F3_{FGC}$ =	Technology impact factor	4-9
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR is not present
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14
	=	$NH3_{FGC\_beforeAPH}$ *$NH3_{FGC\_afterAPH}$ = 0*	
	=	$K_e * B * f_e * I_{NH3}$	4-14 (Eqn 4-14)
	=	0 lb/year	calc
where	K_e =	*see above*	*see above*
	B =	*see above*	*see above*
	f_e =	*see above*	*see above*
	I_{NH3} =	NH_3 injection for dual FGC	4-14
	=	0 ppmv at 6% O_2, wet	Entergy: no ammonia injection
$F2_X$	=	Technology impact factors for processes downstream of the APH (sum of all that apply)	4-12
	=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
	=	0.4 for wet spray tower (PRB coal)	4-22 (Table 4-5 for Wet: Spray Tower for PRB)
	=	1.12 total F2 factors	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM10 emission rate is based on maximum daily HI from 2012-2014 CAMD and stack test factor.
4. Nelson 6 has an existing ESP (per Permit 05220-00014-V2.pdf)

APPENDIX D: MODELING FILES

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April 6, 2017

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RE: Entergy's review of documents provided to LDEQ by U.S. EPA Region 6 on March 10, 2017: "DRAFT BART Analysis for the Nelson Unit 6" and associated cost calculations spreadsheet "Review of CAMx BART Modeling performed by Trinity Consultants for Louisiana Regional Haze"

Dear Ms. Aucoin:

Entergy Services, Inc. on behalf of Entergy Louisiana, Inc. (Entergy) has reviewed the above-referenced documents provided by U.S. EPA Region 6 (EPA) and provides the following comments to assist the Louisiana Department of Environmental Quality (LDEQ) in finalizing its regional haze state implementation plan (SIP). In general, EPA's March 10th critiques are not novel and have been addressed in previous reports and correspondence between Entergy, EPA, and LDEQ, most recently in the response to comments letter provided by Entergy on January 20, 2017, and the Comprehensive Air Quality Model with Extensions (CAMx) Modeling Report submitted on October 14, 2016 (2016 CAMx Modeling Report).

Entergy's continued position is that the Roy S. Nelson Electric Generating Plant (Nelson) Unit 6 should not be subject to any best available retrofit technology (BART) limits. Entergy's submitted CAMx modeling, which is discussed in the latter sections of this letter, demonstrates that Nelson Unit 6 does not contribute towards visibility impairment at either of the nearest Class I areas in any meaningful way, indicating that it should not be subject to BART. However, even if Nelson Unit 6 were found to be subject to BART, the actual costs of compliance for all control technologies evaluated are prohibitive, especially in light of the minimal potential visibility improvements.

The below sections provide responses to EPA's March 10th comments regarding controls costs and the use of CAMx.

<u>"DRAFT BART Analysis for the Nelson Unit 6" and associated cost calculations spreadsheet</u>

As part of the Louisiana Regional Haze SIP development process, Entergy prepared and submitted to LDEQ, on April 14, 2016, a BART five-factor analysis for the Nelson facility (the "2016 BART Analysis"). The project and site-specific costs included in this assessment addressed unit-specific operating parameters that impact the design of each control technology, as well as site-specific constraints that impact constructability and balance-of-plant scope. Therefore, in its "DRAFT BART Analysis for the Nelson Unit 6," EPA should have relied on the site-specific costs provided in the 2016 BART Analysis rather than the generic control system costs generated by the IPM cost algorithms. Moving forward, proper consideration should be given to the actual cost estimates provided by Entergy.

Sargent & Lundy's Site-Specific Control Technology Evaluation

The 2016 BART Analysis included a comprehensive evaluation of control technologies available to reduce sulfur dioxide (SO_2) emissions from Nelson Unit 6. Control technologies assessed in the analysis included dry sorbent injection (DSI), dry spray dryer absorber flue gas desulfurization (SDA), and wet flue gas desulfurization (WFGD).[1] The 2016 BART Analysis was submitted to EPA for review and comment as part of the Louisiana Regional Haze SIP review process.

To support the preparation of its 2016 BART Analysis, Entergy engaged Sargent & Lundy, LLC (S&L) to evaluate the technical feasibility, effectiveness, and costs of various SO_2 control technologies for Nelson Unit 6. S&L performed a site-specific evaluation and prepared a comprehensive technical report for each SO_2 control technology. As part of its evaluation, S&L determined the achievable control efficiency, identified site-specific design considerations, and estimated the total capital investment and annual operating costs of each technology. S&L followed procedures described in 40 CFR Part 51 Appendix Y (the "BART Guidelines") to develop its control system cost estimates for Nelson Unit 6. The BART Guidelines describe the following approach to the development of control system cost estimates:

1) Identify the emission units being controlled;
2) Identify design parameters for the emission controls; and
3) Develop cost estimates based upon those design parameters.

The BART Guidelines note that it is important to specify the control system design parameters and to ensure that the design parameter values will achieve the level of emission control being

[1] Fuel switching to low sulfur coal was also evaluated in the 2016 BART Analysis but was not considered by the EPA.

evaluated. The BART Guidelines require the analyst to document any assumptions regarding the design parameters, and to provide a summary list of equipment and the associated control costs included in the cost estimate. The basis for equipment cost estimates should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source such as the EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (the "Control Cost Manual"). To maintain consistency in BART determinations, the BART Guidelines suggest that cost estimates should be based on the Control Cost Manual, where possible.

The cost estimating methodology described by the Control Cost Manual is directed toward developing a "study" level cost estimate with a nominal accuracy of ±30%.[2] The Manual identifies the following factors that should be provided to develop a study level cost estimate:

- Location of the source within the plant;
- Rough sketch of the process flow sheet (i.e., the relative locations of the equipment in the system);
- Preliminary sizes of, and material specifications for, the system equipment items;
- Approximate sizes and types of construction of any buildings required to house the control system;
- Rough estimates of utility requirements (e.g., electricity);
- Preliminary flow sheet and specifications for ducts and piping;
- Approximate sizes of motors.

The Control Cost Manual includes specific chapters for a number of air pollution control technologies; however, the manual does not include chapters specific to SO_2 emissions controls for coal-fired power plants, including DSI, SDA or WFGD control systems.

The approach S&L used to develop its cost estimates for the Nelson facility is described in each SO_2 control technology report provided as part of the 2016 BART Analysis. In general, S&L identified the emission unit being controlled, established the boundary limits of the air pollution control system, developed the design basis for the control system, and identified the major subsystems and balance-of-plant scope required to install the system. The design basis for each control system is described in each report. Major control system equipment lists, subsystem lists, and balance-of-plant scope is provided in each report. Capital costs for large equipment were derived from S&L's database of control system costs and recent vendor or manufacturer's quotes for similar items, scaled as required for Nelson Unit 6. Annual O&M costs were developed based on site-specific utility and reactant consumption costs. The methodology used by S&L to develop cost estimates for the 2016 BART Analysis followed the approach described in the BART Guidelines and was consistent with the methodology described in the Control Cost Manual.

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[2] Control Cost Manual, Section 1, Chapter 2, pg. 2-3.

EPA's Draft BART Analysis

EPA has now provided to LDEQ a draft BART analysis evaluating the same control technologies included in Entergy's 2016 BART Analysis. However, rather than relying on the unit-specific costs provided in Entergy's 2016 BART Analysis, EPA used IPM cost algorithms to calculate costs for its "DRAFT BART Analysis for the Nelson Unit 6." EPA relied on the IPM cost algorithms to calculate total capital costs, annual control system costs (annualized capital recovery costs plus annual fixed and variable O&M costs), and the cost-effectiveness of each control system on a dollar per ton ($/ton) of SO_2 removed basis. EPA's reliance on the IPM cost algorithms to develop control system costs does not meet the requirements described in the BART Guidelines and is not consistent with the cost estimating approach described in the Control Cost Manual.

The IPM cost algorithms, which were developed by S&L, were based on a statistical evaluation of cost data available from various industry publications. The primary purpose of the IPM cost algorithms is to provide generic order-of-magnitude costs for various air pollution control technologies that can be applied to the electric power generating industry on a system-wide basis to inform an economic impact evaluation of proposed regulatory initiatives, such as the Cross State Air Pollution Rule. The IPM cost algorithms were not intended to substitute for plant-specific costs estimates as they do not take into consideration site-specific costs or constructability issues, are not designed to accurately estimate costs for any specific unit, and do not provide study-level cost estimates.

By necessity, the IPM cost algorithms are designed to require minimal information that can be obtained from publicly available sources. Inputs to the IPM DSI, SDA, and WFGD capital cost algorithms are limited to gross unit size (MW), fuel type, unit heat input or heat rate, and an SO_2 removal efficiency. The IPM cost algorithms are not designed to take into consideration site-specific constructability or balance-of-plant issues, beyond applying a subjective retrofit factor. Therefore, using the IPM cost algorithms to determine project-specific costs is inherently unreliable and unreasonable as it is inconsistent with the Control Cost Manual methodology and does not meet the requirements of the BART Guidelines.

Entergy provided project-specific costs in its 2016 BART Analysis, which addressed unit-specific operating parameters that impact the design of each control technology, as well as site-specific constraints that impact constructability and balance-of-plant scope. EPA should have relied on the site-specific costs provided in the 2016 BART Analysis rather than the generic control system costs generated by the IPM cost algorithms as the basis for its "DRAFT BART Analysis for the Nelson Unit 6." LDEQ should do the same.

"Review of CAMx BART Modeling performed by Trinity Consultants for Louisiana Regional Haze"

On November 9, 2015, Entergy submitted a report to LDEQ for a modeling analysis conducted using CAMx (the "2015 CAMx Analysis"),[3] which is a more advanced model than CALPUFF. This revised analysis demonstrated minimal modeled impacts from Entergy's BART-eligible sources and concluded that none of the Entergy BART-eligible sources are subject to BART. In response, on March 16, 2016, EPA provided comments that called for revisions to the CAMx modeling analysis. Entergy disagreed with these requests, but nevertheless submitted revised modeling results on June 30, 2016. EPA subsequently requested additional revisions to the CAMx modeling methodology that appeared to be technically unsound and would render the CAMx results materially less reliable. The 2016 CAMx Modeling Report prepared by Trinity Consultants, Inc. and All4 Inc. (together: Entergy's consultants) provided a discussion of these additional requested revisions and explained why the methods used in the 2015 CAMx Analysis were more technically defensible than the adjustments requested by EPA.[4]

The modeling comments provided by EPA on March 10th have already been largely addressed by Entergy in the 2016 CAMx Modeling Report, which describes the merits of using CAMx instead of CALPUFF and explains why EPA's requested adjustments would cause the results from CAMx to be unreliable. For a more in-depth discussion of Entergy's CAMx modeling, this 2016 report should be referenced. The below sections reiterate the points made in this report and provide additional clarification as applicable.

Superiority of CAMx over CALPUFF for Nelson's BART Analysis

First, with regard to EPA's revised CALPUFF modeling referenced in the March 10th document, it is Entergy's position that CALPUFF modeling of Nelson Unit 6 should not be given *any* consideration due to its inability to accurately characterize visibility at the distances at issue with respect to the Nelson facility. Both the Caney Creek Wilderness Area (Caney Creek) and the Breton Wilderness Area (Breton) are over 400 km away from the facility, which are distances well beyond the recommended distance threshold for CALPUFF use.[5]

The CAMx modeling system, on the other hand, is significantly more robust than the CALPUFF modeling system and alleviates many of the concerns about CALPUFF's accuracy. CAMx includes full chemistry, which allows for more accurate characterization of reactions taking place in the

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[3] "Updated BART Applicability Screening Analysis." Prepared for Entergy by Trinity Consultants, November 9, 2015.

[4] "CAMx Modeling Report." Prepared for Entergy by Trinity Consultants and All4, October 14, 2016, attached as part of Appendix D to the LDEQ SIP proposal dated October 20, 2016.

[5] *"IWAQM recommends use of CALPUFF for transport distances of order 200 km and less. Use of CALPUFF for characterizing transport beyond 200 to 300 km should be done cautiously with an awareness of the likely problems involved."* Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, December 1998.

atmosphere. The use of nested grids, the Particulate Matter Source Apportionment Tool (PSAT), and full chemistry Plume-in-Grid (PIG) allows for finer resolution and better characterization of plume transport, dispersion, and chemistry for individual point sources. CALPUFF analyses conducted in support of BART do not consider the full inventory of sources and, thus, do not account for other pollutants challenging and consuming precursor emissions. As such, ammonia and other precursor pollutants are more fully available to react with a facility's emissions and generate haze in a modeled simulation using CALPUFF, which contributes to over-predictions of impacts. Because CALPUFF does not accurately reflect the interaction of pollutants in the atmosphere, and because of the distance involved for modeling the Nelson plant, CALPUFF modeling should not be considered in determining whether Entergy's BART-eligible sources are subject to BART.

Modeling Maximum 24-hour Emission Rates

The first item raised by EPA in regard to Entergy's CAMx modeling is related to modeled emission rates. EPA insists that maximum 24-hour emission rates must be utilized with CAMx in accordance with the BART guidelines. EPA's argument is based on the application of these guidelines (including the recommendation to use maximum 24-hour emissions), which were issued in 2005 and limited by the then-available modeling capabilities, being designed for a single-source, simplified-chemistry model as compared to the current modeling capabilities available with a multi-source, advanced-chemistry photochemical model, such as CAMx, and its ability to better characterize visibility.

The conservatism built into the BART protocol (e.g., maximum 24-hour emission rates, annual average ammonia concentrations, etc.), in part in response to the then-model-capabilities of CALPUFF, does not allow for accurate representation of temporal considerations. Likewise, CALPUFF's inherent limitations prevent it from providing modeled impacts with meaningful relationships to modeled dates. If CALPUFF BART modeling undertaken according to the BART protocol is neither capable of nor intended to differentiate modeled impacts from one hour to the next or provide any indication of when impacts occur (but instead to estimate an overall maximum impact for the modeled meteorological period), it would perhaps be appropriate to model worst-case emissions for every modeled day. However, given CAMx's superior ability to characterize temporal, hour-to-hour conditions, utilizing a worst-case emission rate is unnecessary and further, unreasonable in part because such a modeled rate likely overstates an individual source's actual visibility impacts. According to Entergy's consultants, the CAMx model's capability to provide a complete representation of emissions, chemistry, transport, deposition, and temporal considerations is skewed if the emissions from a select few sources are inflated. In other words, *the use of maximum 24-hour emissions creates an implicit bias against the BART sources, which causes the CAMx predictions (as altered by EPA's requested adjustments) to be an unrealistic representation of the impact or contribution from those sources – and inherently unreliable.*

Post-Processing CAMx Model Output for BART Assessments

The remaining comments regarding Trinity's CAMx modeling pertain to the post-processing methodology. Although CAMx is a more robust modeling system than CALPUFF, CAMx is still subject to the concerns about potential model performance issues upon which all air quality models are contingent. In its Response to Comments regarding the Texas and Oklahoma FIP for Regional Haze, EPA admits that "any bias issues in CAMx are ameliorated by tethering the model to real monitoring data, through the use of relative response factors generated by modeling of base and future cases to predict future monitored values."[6] This use of relative response factors (RRFs) combined with actual monitor data gathered by the Interagency Monitoring of Protected Visual Environments (IMPROVE) program is the methodology utilized in Entergy's 2015 CAMx Analysis modeling. Entergy's consultants have determined that EPA's proposed methodology, which is based on applying CALPUFF modeling principles to CAMx processing, is technically unsound and should not be used for CAMx modeling analyses.

In its March 10th comments, EPA states that the use of the RRF methodology—an accepted method to account for model bias—is *not* acceptable for BART analyses using CAMx. EPA insists that a limited, CALPUFF-based methodology must be utilized without offering any alternate paths for ameliorating model bias. Therefore, EPA is recommending that the direct-modeled absolute maximum impacts output from CAMx should be utilized as the metric of choice for visibility impairment, despite the likelihood that this method overstates impacts because it fails to account for model bias. Entergy believes that the post-processing methodology used in the 2015 CAMx Analysis (RRFs combined with IMPROVE monitor data) represents the most appropriate and technically defensible evaluation of CAMx modeling outputs for visibility purposes. Additional details regarding EPA's requested adjustments to both the modeled emission rates and post-processing methodology can be found in the 2016 CAMx Modeling Report.

Clean Versus Dirty Background Evaluations

EPA's modeled anticipated visibility baseline impacts and benefits due to proposed controls on Nelson Unit 6 are based on a clean background approach, which evaluates the impact of Nelson Unit 6 against a natural background (i.e., the conditions under which no man-made sources are impacting a Class I area). This methodology assumes that the source of interest is the only source contributing to the overall visibility at the Class I area and no other sources will be influencing the visibility conditions. Therefore, visibility impacts calculated using the clean background methodology are an artificial visibility metric that does not necessarily correspond to the actual visibility conditions in a Class I area.

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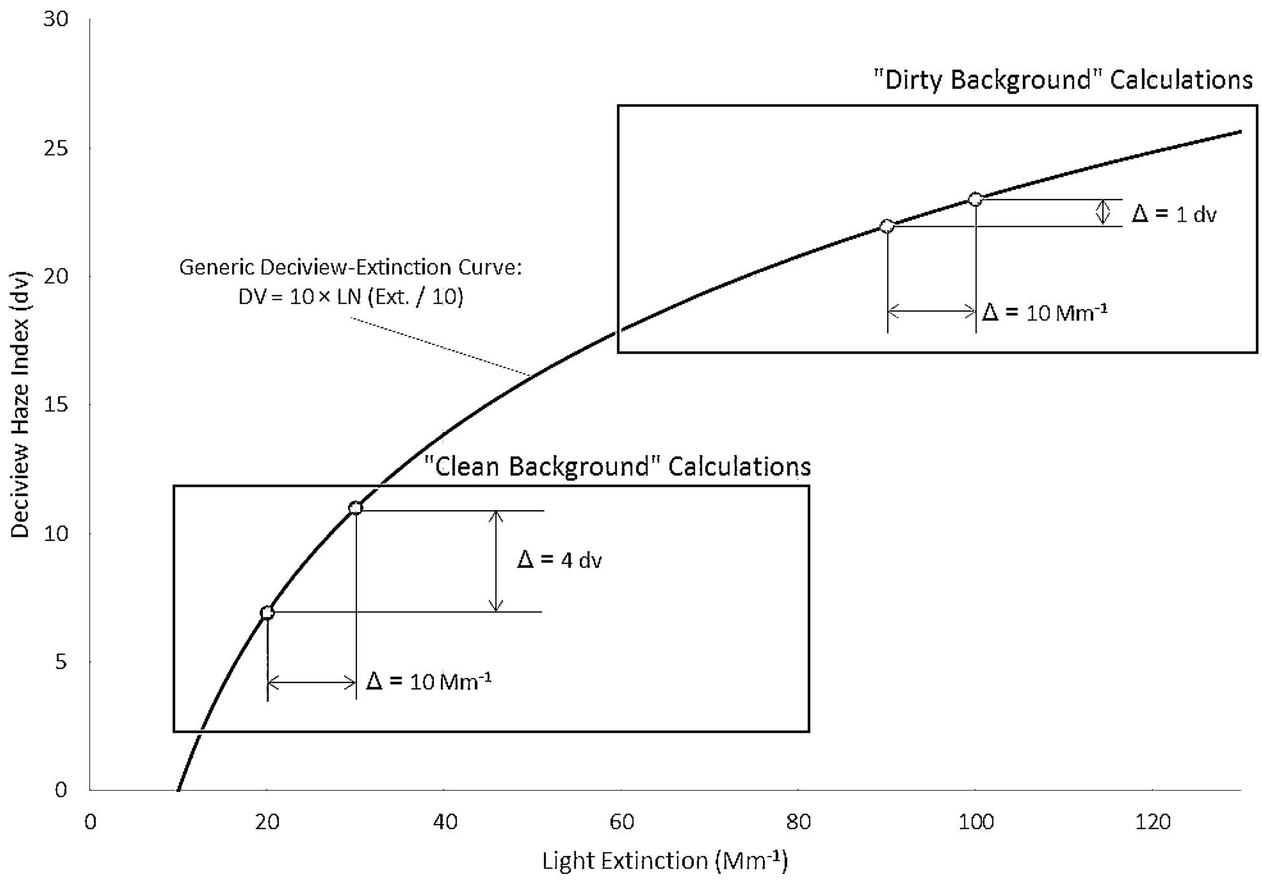
[6] "Response to Comments for the Federal Register Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze." December 9, 2015.

Depending on the background condition at which potential control technology visibility improvements are evaluated (i.e., where on the deciview visibility curve the benefits are applied), the logarithmic nature of the deciview metric can result in widely varying deciview improvements for identical extinction changes. For example, hypothetically, a clean background approach might translate a 10 Mm^{-1} change in light extinction into a 4 dv improvement, while the same 10 Mm^{-1} change might equate to only 1 dv relative to dirty background conditions. Figure 1 below illustrates this general example of logarithmic variation.

Figure 1. Deciview-Extinction Curve – Generic Comparison of Clean and Dirty Background Calculations



The CAMx modeling system is capable of incorporating the influence and contribution of all emissions inventory sources (including both biogenic and anthropogenic sources) into its visibility projections (giving one of several reasons for its better predictive value over CALPUFF). This allows CAMx to estimate the visibility baseline impacts and control technology benefits based on the dirty background methodology, resulting in more realistic visibility predictions relative to the actual visibility conditions during a given time period. Therefore, the baseline visibility impacts and benefits from controls estimated by CAMx using the dirty background methodology will be closer to the actual visibility improvement expected at a given Class I area in the near term than values estimated based on the clean background methodology. See Figures below (CAMx v. CALPUFF v. Actual IMPROVE data). EPA's clean background projected visibility impacts and control technology benefits for Nelson Unit 6 are unreliable indicators of actual conditions, especially when combined with EPA's other reliability-impairing modeling adjustments (e.g., maximum 24-hour emissions, post-processing without RRFs, etc.).

Figure 2. Observed (IMPROVE) Percent of Total Extinction by Species for 20% Worst Days at Breton Wilderness Area

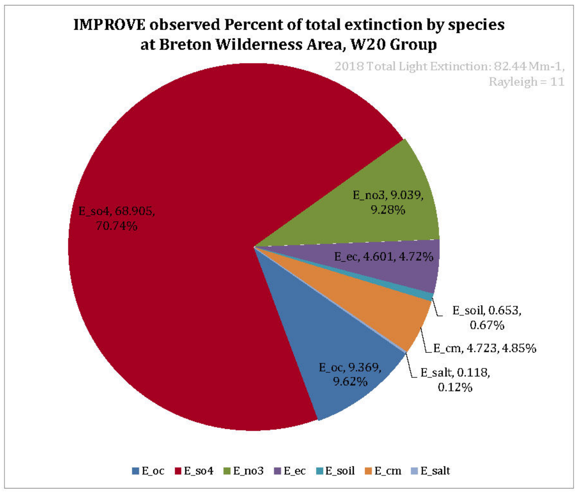


Figure 3. CALPUFF Predicted Percent of Total Extinction by Species for 20% Worst Days at Breton Wilderness Area

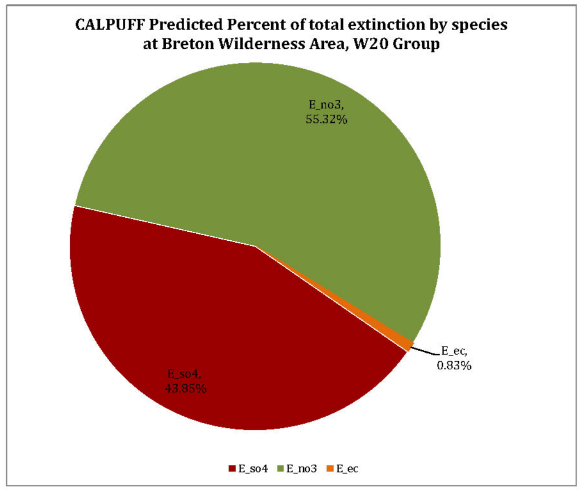
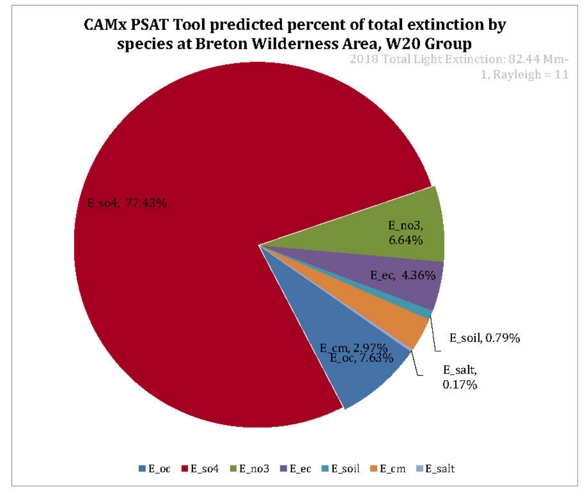


Figure 4. CENRAP CAMx PSAT Tool Predicted Percent of Total Extinction by Species for 20% Worst Days at Breton Wilderness Area



Conclusion

As presented in the 2016 BART Analysis, based on the dirty background post-processing methodology described in the 2016 CAMx Modeling Report, the baseline impact of Nelson Unit 6 is 0.019 dv at Caney Creek and 0.012 dv at Breton. The subsequent visibility benefits due to any of the add-on control options evaluated are therefore *at most* 0.019 dv and 0.012 dv at Caney Creek and Breton, respectively. This equates to a cost of $3 billion or more per dv improvement.

Thus, Entergy continues to believe that Nelson Unit 6 should not be subject to BART. Entergy's CAMx modeling, which utilizes a more technically defensible modeling approach, demonstrates that Nelson Unit 6 does not meaningfully contribute to visibility impairment at either of the nearest Class I areas. If Nelson Unit 6 were nonetheless found to be subject to BART, SO_2 controls are not warranted for Nelson in light of the prohibitive actual costs of all control technologies evaluated and the minimal visibility benefits that potentially could be achieved from such controls.

Thank you for your consideration of this information. Please contact me with any questions or concerns.

Sincerely,

ENTERGY SERVICES, INC.

KMcQueen

Kelly McQueen
Assistant General Counsel – Environmental (Lead)

Response of: Entergy Texas, Inc.	Prepared By: Omar El-Shal, Daniel Boratko, Phong Nguyen
to the Fourth Set of Data Requests of Requesting Party: Sierra Club	Sponsoring Witness: Anastasia R. Meyer Beginning Sequence No. EV2425 Ending Sequence No. EV2429

Question No.: SIERRA 4-2 Part No.: Addendum:

Question:

Refer to the Direct Testimony of Company Witness Meyer page 15 regarding ETI's plan to keep Nelson 6 online through [redacted] because it believes it will be short on capacity if the unit retires earlier.

a. Indicate whether the Company issued any request for proposals (RFPs) over the past 5 years or undertook any other efforts to procure replacement resources to address the capacity shortfall it anticipates will occur when Nelson 6 retires.

   i. If yes, provide the results of the RFP.

   ii. If no, explain why no other procurement efforts have been made to date.

b. Indicate whether the Company's generation capacity needs when Nelson 6 retires are system wide or specific to the location where Nelson 6 is located.

   i. If ETI has location-specific needs, provide all analysis and reports supporting the specific needs.

c. Indicate how must lead time the Company assumes it needs to bring the following supply-side resources online in its planning exercises:

   i. Solar PV

   ii. Wind

   iii. Battery Storage

   iv. Paired solar and battery storage

   v. Combined Cycle Plant

   vi. Combustion Turbine Unit

Response:

a. Entergy Texas, Inc. ("ETI") generally does not issue Request for Proposals ("RFPs") to procure replacement for a single resource deactivation. Rather, ETI takes a holistic approach and issues RFPs to meet ETI's broader resource adequacy and planning needs. This includes the needs identified in recent ETI RFPs such as the 2019 ETI Solar RFP, 2020 ETI CCGT RFP, 2021 ETI Solar RFP, and the recently issued 2022 ETI Renewable RFP.

b. ETI's generation capacity needs when Nelson 6 deactivates are system wide. However, ETI expects future generation capacity located near the Beaumont & Port Arthur region to yield economic benefits to its customers due to the potential for load growth in the area. Those benefits will be evaluated in future resource planning analyses.

c. As part of the planning process, ETI assumes the following lead times for placing new resources in operations:

Phase	*Development*	*Construction & Testing*
Solar PV	2.5 years	2 years
Wind	2.5 to 3 years	2 to 3 years
Battery Storage	2.5 years	1 year
Paired solar and battery storage	3 years	2 years
Combined Cycle Plant	1.5 to 2 years	3 years
Combustion Turbine Unit	1.5 to 2 years	2.5 years

DESIGNATION OF PROTECTED MATERIALS PURSUANT TO PARAGRAPH 4 OF DOCKET NO. 53719 PROTECTIVE ORDER

The Response to this Request for Information includes Protected Materials within the meaning of the Protective Order in force in this Docket. Public Information Act exemptions applicable to this information include Tex. Gov't Code Sections 552.101 and/or 552.110. ETI asserts that this information is exempt from public disclosure under the Public Information Act and subject to treatment as Protected Materials because it concerns competitively sensitive commercial and/or financial information and/or information designated confidential by law.

Counsel for ETI has reviewed this information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the Protected Materials Designation.

Kristen F. Yates
Entergy Services, LLC.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.	Prepared By: Charles DeGeorge, David Triplett
to the Fourth Set of Data Requests	Sponsoring Witness: Anastasia R. Meyer
of Requesting Party: Sierra Club	Beginning Sequence No. EV2430
	Ending Sequence No. EV2432

Question No.: SIERRA 4-3 Part No.: Addendum:

Question:

Refer to Exhibit ARM-3 HSPM regarding the Nelson 6 Deactivation Analysis, page 2 regarding the increased environmental regulations the plant is subject to.

a. When did the Company's Environmental Policy program first became aware that significant investment in emissions controls could be required to comply with the Regional Haze Program.

b. Provide all studies and analysis the Company completed to evaluate the cost of complying with the Regional Haze Program, whether part of the first or second planning period of the Haze Program.

c. Has Entergy conducted any analysis of the potential compliance costs at Nelson 6 to comply with EPA's proposed Good Neighbor Rule, 87 Fed. Reg. 20,036 (Apr. 6, 2022)? If not, why? If so, please provide all documents reflecting such analyses.

d. Confirm that Louisiana is part of the Group 3 Trading Program under EPA's Update to the Cross State Air Pollution Rule. If not confirmed, please explain which Trading Group to which Louisiana belongs.

e. Please provide the total number of NOx credit purchases under CSAPR and cost by year for Nelson 6 from 2017 to present.

f. Does ETI have a forecast for NOx credit costs under CSAPR? If yes, please provide all forecasts through 2030. If not, why?

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

a. Implementing regulations for the United States Environment Protection Agency's Regional Haze program were first promulgated in July of 1999, and Entergy has monitored the program in order to determine when emissions controls investments have been or may be required.

b. Please see the Company's response to Sierra Club 4-1, subpart b.

c. Entergy has evaluated cost estimates prepared by the Environmental Protection Agency ("EPA") in support of the proposed revisions to the Cross-State Air Pollution Rule ("CSAPR"), which were released in April 2022. This evaluation is included in comments submitted to the EPA on June 21, 2022 in the CSAPR regulatory docket. Please see the Company's response to Sierra Club 4-1, subpart b.

d. Yes, Louisiana is currently part of the Group 3 trading program under EPA's update to the CSAPR program. No CSAPR allowances have been purchased specifically to cover ETI's compliance obligation at Nelson 6 for the period of 2017 to date.

e. Please see the highly sensitive attachment (P-53719-00SIE004-X003_HSPM) for third party forecasts.

Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

<u>DESIGNATION OF PROTECTED MATERIALS PURSUANT TO PARAGRAPH 4 OF DOCKET NO. 53719 PROTECTIVE ORDER</u>

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Counsel for ETI has reviewed this information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the Protected Materials Designation.

<u>Kristen F. Yates</u>
Entergy Services, LLC.