

# Four Factor Analysis Regional Haze Rule Second Decadal Review

Avon Lake Power Plant  
Unit 9/Boiler 12

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## 1. Introduction

The Ohio Environmental Protection Agency (Ohio EPA) Division of Air Pollution Control held a Regional Haze Update meeting on June 29, 2020 to reach out to affected facilities to request a four-factor analysis. Ohio EPA is developing a State Implementation Plan (SIP) for the Second Decadal Review period of the federal Regional Haze Rule (42 USC §7491 – Visibility Protection for Federal Class I Areas). The Regional Haze Rule (RHR) requires state and federal agencies to work to improve visibility in U.S. National Parks and Wilderness Areas throughout the country (see 40 CFR §81.401 through 81.437) with the ultimate goal of achieving “natural background” visibility in these Class I areas by the year 2064. Every ten years, agencies are required to evaluate their plans and consider whether additional emission reductions at certain major sources are warranted to continue realizing “reasonable progress” in visibility improvement. Ohio EPA identified the Avon Lake Power Plant Unit 9/Boiler 12 (referred to as Unit 9 in this report) as a source requiring an analysis for potential reductions of sulfur dioxide (SO<sub>2</sub>) emissions and nitrogen oxides (NO<sub>x</sub>) emissions.

As outlined in the RHR, this analysis, referred to as a “Four-Factor Analysis”, needs to first identify all technically feasible control technologies for additional SO<sub>2</sub> and NO<sub>x</sub> emissions control. Each feasible control option then needs to be evaluated relative to the following four statutory factors:

1. Cost of implementing emission controls;
2. Time necessary to install such controls;
3. Energy and non-air quality impacts associated with installing controls; and
4. The remaining useful life of the facility.

At the June 29, 2020 Regional Haze Update meeting, Ohio EPA requested the Avon Lake Power Plant to perform the subject analysis for Unit 9 and submit their findings to the Ohio EPA. Appendix A presents Avon Lake Power Plant’s slide from Ohio EPA’s Region Haze Update meeting presentation. Avon Lake Power Plant contracted AECOM to assist with the analysis. Although not required to be included in the analysis, states have the option to consider a fifth factor – evaluation of visibility benefits - in addition to the four statutory factors when making their reasonable progress determinations. This analysis includes the fifth factor (see Section 6) to provide additional information to Ohio EPA to assist in their consideration of controls for visibility improvement.

This report provides a description of the affected source including existing emission controls (Section 2), a summary of the actions taken during First Decadal Review period of the RHR (Section 3), a summary of actual baseline emissions (Section 4), identification of potentially feasible control options and an assessment of each of the four statutory factors for these options (Section 5). Additionally, Section 6 provides a “fifth factor” analysis of the prospective visibility impacts to Class I areas of potential SO<sub>2</sub> and NO<sub>x</sub> controls for Ohio EPA’s consideration. Finally, Section 7 presents a summary of this report’s findings.

## 2. Source Description and Emission Controls

Avon Lake Power Plant is located at 33570 Lake Road, Avon Lake, OH 44012. The Plant is licensed to operate under Ohio EPA’s Title V Operating Permit No. P0085253 (Expiration date – April 18, 2022). Unit 9 is listed in the Title V permit as Boiler B012.

Avon Lake Power Plant Unit 9 was designed as a pulverized coal-fired boiler to burn bituminous coal with a steam turbine-driven electric generator that provides electricity to the regional electric grid. The unit was manufactured by Babcock and Wilcox and commissioned in 1970. Unit 9 fired primarily Eastern Bituminous coal until 2016 when the fuel was changed to a Western Bituminous and Powder River Basin coal blend. The nominal rated heat input capacity for the boiler, based on the Title V permit is 6,040 MMBtu/hr and the power output is approximately 652 MW (gross), and 627 MW (net).

Emissions of SO<sub>2</sub> have been limited since June 2016 by the use of Western coals and a limit accepted for compliance with SO<sub>2</sub> Data Requirements Rule compliance modeling. The boiler is equipped with the Low-NOx cell burners and overfire air<sup>1</sup>. A high-efficiency electrostatic precipitator (ESP) is present on Unit 9 for particulate matter (PM) control.

The use of Western coals and dry sorbent injections (hydrated lime and activated carbon), as needed, provides compliance with the Coal- and Oil-Fired Electric Utility Steam Generating Units (EGU) National Emission Standards for Hazardous Air Pollutants (NESHAP) Rule, also known as the Mercury and Air Toxics Standards (MATS) Rule (40 CFR Part 63, Subpart UUUUU).

Unit 9 is also subject to, and compliant with, the Cross-State Air Pollution Rule (CSAPR or Transport Rule) and the related requirements promulgated under Ohio Administrative Code (OAC) 3745-14 and OAC 3745-109 and 40 CFR 75 - Continuous Emissions Monitoring. Avon Lake Power Plant operates and maintains (i) certified continuous emission monitoring systems (CEMs) for NO<sub>x</sub>, SO<sub>2</sub> and carbon dioxide (CO<sub>2</sub>) and (ii) a certified exhaust gas stream flow monitor at the exhaust duct. Certified emissions, heat input and gross electrical load data are submitted quarterly to the U.S. Environmental Protection Agency (EPA).

In summary, contemporary emission control devices are already installed, operated and maintained on Unit 9, and these devices provide for effective control of criteria and hazardous air pollutants.

### **3. First Regional Haze Planning Period Reasonable Progress Determination**

During the First Decadal Review period of the RHR (i.e., 40 CFR 51 Subparts 308 and 309), Unit 9 was subject to Best Available Retrofit Technology (BART) review because it had been placed into service within the rule-specified BART applicability window (between August 7, 1962 and August 7, 1977) and satisfied the other eligibility criteria. BART requirements for SO<sub>2</sub> and NO<sub>x</sub> emissions were satisfied by compliance with EPA's Clean Air Interstate Rule (CAIR), now superseded by the more stringent CSAPR, per EPA who ruled that CAIR achieved greater reasonable progress than BART for SO<sub>2</sub> and NO<sub>x</sub> emissions at BART-eligible electric generating units located in CAIR-affected states.

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<sup>1</sup> In 2005, Energy Systems Associates installed a temporary demonstration selective noncatalytic reduction (SNCR) system in order to reduce NO<sub>x</sub> emissions during the ozone season. The goal of the project was to achieve 20% NO<sub>x</sub> control during ozone season. The SNCR system last operated during the summer of 2009. There is very little remaining from the old, temporary system and the remaining items would need significant upgrades to be re-purposed. Therefore, reuse is likely to be more costly than a new, replacement system.

## 4. Source Emissions

Actual emissions for Unit 9 are summarized in **Table 4-1**. At the Avon Lake Power Plant, Unit 9's actual emissions of SO<sub>2</sub> have been reduced from 2006-2008 period (indicative of the baseline used for the first RHR planning period) to 2017-2019 period by 92% and emissions of NO<sub>x</sub> have been reduced by 79% for that same period. The emission reductions are attributable to the use of Western coal (resulting in a factor-of-3 reduction in SO<sub>2</sub> emissions) and lower plant utilization.

**Table 4-1 Avon Lake Power Plant – Unit 9 Actual Annual Operation and Emissions**

Time Period	Annual Operating Hours <sup>(a)</sup>	Power Output <sup>(a)</sup>	Capacity Factor based on MWh <sup>(b)</sup>	Annual Fuel Use <sup>(a)</sup>	SO <sub>2</sub> Emissions <sup>(a)</sup>		NO <sub>x</sub> Emissions <sup>(a)</sup>	
	(hr/yr)	(MWh)	%	(MMBtu/yr)	(ton/yr)	(lb/MMBtu)	(ton/yr)	(lb/MMBtu)
2006 through 2008	6,282	3,019,366	52.9%	27,687,294	30,500	2.20	5,182	0.374
2017 through 2019	1,803	748,172	13.1%	6,726,692	2,404	0.71	1,065	0.317
Emission Reduction					92%	--	79%	--
<p>(a) EPA Air Markets Program Data (<a href="https://ampd.epa.gov/ampd/">https://ampd.epa.gov/ampd/</a>)            (b) Rated capacity for Unit 9 is 652 MW, gross.            (c) The old SO<sub>2</sub> permit limit on Unit 9 (Boiler 12) was 4.65 lb/MMBtu. The new combined SO<sub>2</sub> permit limit on Boilers 10 and 12 is 1.59 lb/MMBtu (30-day average). This reduction in permit limit has resulted in a large reduction in the potential emissions of SO<sub>2</sub> from Unit 9.</p>								

## 5. Emissions Control Options

This section presents an evaluation of potential emissions reduction options applicable for SO<sub>2</sub> and NO<sub>x</sub> emissions at Unit 9. The evaluation starts with listing potential control options and determining if the option is technically infeasible. For those options considered technically feasible, an analysis will be conducted considering the four statutory factors: (1) costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of the emission unit. Following that evaluation are conclusions related to the feasibility and reasonability of implementing the remaining approaches.

### 5.1 Identification of Potentially Available SO<sub>2</sub> Emissions Reduction Options

The Avon Lake Power Plant requested and received a Director's Exemption to install gas fired burners on Unit 9 in 2014. The ability to fire gas for normal production was contingent upon construction of a gas pipeline to supply the necessary quantity of gas from interstate transmission lines. Acquiring the necessary right of ways and approvals proved challenging and the project was eventually indefinitely suspended by NRG (former Owner/Operator of Avon Lake). As such, gas supply has proven inadequate and the control option of evaluating natural gas as an alternative fuel is not being studied further as part of this four-factor analysis. Also, as noted previously, Unit 9 fired primarily Eastern Bituminous coal until 2016 when the fuel was changed to a Western Bituminous and Powder River Basin coal blend, which has a lower sulfur content (SO<sub>2</sub> ~ 0.71 lb/MMBtu) than Eastern Bituminous coal (SO<sub>2</sub> ~ 2.20 lb/MMBtu). The blend

of fuels selected is designed to permit full operation of the unit at emissions rates that comply with SO<sub>2</sub> limits and the MATS rule. Therefore, fuel switching for SO<sub>2</sub> NAAQS and MATS compliance has been implemented and further evaluation of a lower sulfur fuel option is not warranted.

There are multiple add-on control options for controlling the emissions of SO<sub>2</sub> from coal-fired power plants. These options fall in three general categories:

1. Dry Sorbent Injection (DSI).
2. "Dry" FGD (e.g.; spray dryer absorber (SDA), circulating dry scrubbers (CDS), or novel integrated desulfurization (NID)); and,
3. Wet Flue Gas Desulfurization (wet FGD);

A DSI system involves the injection of a lime or limestone powder into the exhaust gas stream. The stream is then passed through a baghouse to remove the sorbent and entrained SO<sub>2</sub>. Unit 9 already has a DSI system for hydrochloric acid (HCl) emission control under the MATS Rule. The system was intended for, and designed to address acid gas emissions for MATS compliance. Therefore, the existing DSI system on Unit 9 does not provide significant SO<sub>2</sub> emission control due to a variety of factors including residence time, gas stream temperature, the amount of sorbent injected, and the use of an ESP (as opposed to a fabric filter) for PM emissions control. High sorbent injection rates required for any appreciable SO<sub>2</sub> control would exceed the capability of the existing ESP to handle particulate emissions. Therefore, implementing upgrades to the existing DSI system is not a practical control option and is not evaluated further as a complete dry scrubber (Spray Dry Absorber "SDA") or wet FGD is required for achieving SO<sub>2</sub> emissions control on Unit 9.

An SDA system is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO<sub>2</sub> is absorbed by the droplets. The absorption of the SO<sub>2</sub> leads to the formation of calcium sulfite (CaSO<sub>3</sub>•2H<sub>2</sub>O) and calcium sulfate (CaSO<sub>4</sub>). The heat of 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 that is carried out with the gas and collected with a fabric filter. Process equipment associated with an SDA control system includes an alkaline storage tank, mixing and feed tanks, atomizer assembly, spray chamber module, integrated fabric filter, and solids recycle system. The recycle system collects solid reaction byproducts and recycles them back to the spray dryer feed system to maximize reactant utilization.

For Unit 9, SDA does not offer advantages compared to wet FGD due to site specific issues such as the cost for replacement of the upgraded ESP with a costly new fabric filter for PM emission control. However, for completeness, we have evaluated the cost of installing an SDA system on Unit 9.

As discussed in the sections below, an SDA system and wet FGD system were evaluated further for the four statutory factors.

### 5.1.1 Costs of Compliance (Factor 1)

In December 2009, URS Washington Group<sup>2</sup> estimated the total capital cost of a wet FGD system at \$389 million. Escalation of the URS capital cost from 2009 estimate to a 2019 cost based on the Chemical Engineering Plant Cost Index<sup>3</sup> (607.5/521.9) indicates a current capital

<sup>2</sup> "FGD and SCR Retrofit Budgetary Cost Estimate and Schedule", Project number 27709-269. Prepared for RRI Energy's Avon Lake Unit 9. Prepared by Washington Division of URS Corporation. Included as Appendix D of this report.

<sup>3</sup> <https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/>

cost of \$453 million. For this analysis, the capital costs for wet limestone FGD and the SDA system were estimated using EPA's Clean Air Markets Retrofit Cost Analyzer<sup>4</sup>.

The wet FGD cost estimated in the 2009 study could not have accounted for the compounded space constraints presented by installation of DSI system and activated carbon injection (ACI) system (MATS controls). **Figure 5-1** presents the current unusual and complicated layout of the Avon Lake Power Plant's Unit 9. **Figure 5-2** shows a site plan for a wet FGD system for Avon Lake Power Plant. As shown in the figures, there is very limited space available around Unit 9 for installation of an SO<sub>2</sub> scrubbing system including a new wet stack. There is also inadequate space available for staging and assembly of equipment. The fabrication and assembly would have to be done offsite and transported to the Plant which is a significant cost adder. As such, a retrofit factor of 1.2 is justified and is, in fact, a conservatively low estimate of the challenges associated with these retrofits.

**Figure 5-1 Avon Lake Power Plant Unit 9**



<sup>4</sup> Available at: <https://www.epa.gov/airmarkets/retrofit-cost-analyzer>. The EPA Control Cost Manual draft (<https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0341-0082>) uses the equations from the Retrofit Cost Analyzer; therefore, the two are equivalent in purpose and outcome.



Office of Management and Budget (OMB) uses an interest rate of 7%.<sup>8</sup> OMB Circular A-4 states the following:

*"As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."*

As a privately held wholesale power generator and not a public utility or subsidiary thereof, GenOn's cost of capital is significantly higher than the bank prime rate and the default 7% rate. GenOn's estimates that the cost of capital to finance an emissions control project at Avon Lake would be similar to other independent coal plant projects in the area. Examples for financing of two other independent coal plants ranged from 11.5 to 12.5%<sup>9</sup>. These rates equate to a pre-tax average cost of capital of 15 to 20%. For this analysis, 7% was determined to be exceedingly conservative. Therefore, a firm-specific interest rate of 7% was used for this analysis.

The EPA Control Cost Manual states that the remaining useful life of a new dry or wet SO<sub>2</sub> scrubbing system should be assumed to be 20 - 30 years.<sup>10</sup> EPA's RHR guidance states that the remaining useful life is the number of years that the new control equipment is expected to be in service. Although the remaining useful life of a new control system may be 30 years, the remaining useful life of an existing, 50-year old EGU may be far less than 30 years due to age and economic competition from other sources of electricity. During the first regional haze planning period, a 20-year useful life was used as a default for amortization purposes. Even that has proven to be overly optimistic as approximately 30% of the coal-fired generation capacity in the U.S. has been retired in the 10-year period since 2009. Additional retirements have been announced and are expected to continue due to competition from natural gas-fired combined cycle units and renewable energy.<sup>11</sup> President Biden signed an Executive Order on January 27, 2021 entitled Executive Order on Tackling the Climate Crisis at Home and Abroad. In that order, he states the federal government's intent to implement a carbon-free electric power supply sector by 2035.

While there is no definitive retirement date established for Unit 9, we believe that a remaining useful life of 20 years is more than reasonable for planning purposes. Per Ohio EPA's request, capital recovery costs are also being calculated based on a 30-year remaining useful life to demonstrate the sensitivity of the annualized cost to this parameter.

The total estimated annual cost for wet limestone FGD is \$51.6 million/yr while that for an SDA system is \$44.5 million/yr (based on 20-year life, a 7% interest rate and a retrofit factor of 1.2). **Tables 5-1 and 5-2** include annual costs for alternative, hypothetical equipment lifetimes and retrofit factors.

Variable operating costs are relatively low due to the low annual capacity factor. The total annual cost is equivalent to about \$69/MWh of power produced. The cost effectiveness for a wet FGD system is \$22,600 per ton of SO<sub>2</sub> controlled and that of an SDA system is \$19,500 per

<sup>8</sup> OMB Circular A-4, <https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf> - "

<sup>9</sup> Longview Power, LLC bankruptcy exit financing LIBOR + 10% (7/31/20); Homer City Generation LP; bankruptcy exit financing LIBOR + 11% (12/31/20)

<sup>10</sup> The EPA Control Cost Manual draft (<https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0341-0082>), Section 1.1.5.

<sup>11</sup> The Energy Information Administration (EIA) has information regarding planned electric generating unit closures through 2058. From 2020 through 2028, an equivalent of 43 gigawatts of fossil fuel generation capacity will be retired. [https://www.eia.gov/epm/table\\_grapher.php?t=table\\_6\\_06](https://www.eia.gov/epm/table_grapher.php?t=table_6_06).

ton of SO<sub>2</sub> controlled. The high cost per ton of pollutant controlled is attributable to the high capital costs associated with these add-on SO<sub>2</sub> controls and the low annual capacity factor (which would likely be further reduced by additional controls costs). In reality, the cost of the controls is a multiple of the existing average PJM wholesale electricity cost of \$20 to \$30/MWh. This level of control cost adder is unsustainable for a competitive independent power producer.

**Table 5-1 Avon Lake Power Plant: Unit 9 Wet FGD Cost Analysis**

Cost Item	Case A-1 <sup>(1)</sup>	Case A-2 <sup>(2)</sup>	Case B-1 <sup>(3)</sup>	Case B-2 <sup>(4)</sup>
Total Capital Investment, \$	\$483,000,000	\$483,000,000	\$403,000,000	\$403,000,000
Annual Costs				
Capital Recovery, \$/yr	\$45,600,000	\$38,900,000	\$38,000,000	\$32,500,000
Fixed costs (fixed O&M labor, fixed O&M materials, fixed O&M administrative), \$/yr	\$5,200,000	\$5,200,000	\$5,200,000	\$5,200,000
Variable costs (limestone, waste disposal, electric power, wastewater treatment), \$/yr	\$760,000	\$760,000	\$760,000	\$760,000
Total annual cost, \$/yr	\$ 51,600,000	\$44,900,000	\$44,000,000	\$38,500,000
SO <sub>2</sub> emissions before control, ton/yr	2,404	2,404	2,404	2,404
SO <sub>2</sub> emissions after control, ton/yr	120	120	120	120
SO <sub>2</sub> emissions Controlled, ton/yr	2,284	2,284	2,284	2,284
Cost effectiveness, \$/ton SO <sub>2</sub> controlled	\$22,600	\$19,600	\$19,200	\$16,800
<p>(1) Capital recovery charges calculated based on 20-year life, a 7% interest rate and a retrofit factor of 1.2. Annual cost without AFUDC is \$20,700/ton SO<sub>2</sub> controlled.  (2) Capital recovery charges calculated based on 30-year life, a 7% interest rate and a retrofit factor of 1.2.  (3) Capital recovery charges calculated based on 20-year life, a 7% interest rate and a retrofit factor of 1.0.  (4) Capital recovery charges calculated based on 30-year life, a 7% interest rate and a retrofit factor of 1.0.</p>				

**Table 5-2 Avon Lake Power Plant: Unit 9 SDA Cost Analysis**

Cost Item	Case A-1 <sup>(1)</sup>	Case A-2 <sup>(2)</sup>	Case B-1 <sup>(3)</sup>	Case B-2 <sup>(4)</sup>
Total Capital Investment, \$	\$417,000,000	\$417,000,000	\$347,000,000	\$347,000,000
Annual Costs				
Capital Recovery, \$/yr	\$39,400,000	\$33,600,000	\$32,800,000	\$28,000,000
Fixed costs (fixed O&M labor, fixed O&M materials, fixed O&M administrative), \$/yr	\$5,200,000	\$5,200,000	\$5,200,000	\$5,200,000
Variable costs (lime, waste disposal, electric power), \$/yr	\$1,200,000	\$1,200,000	\$1,200,000	\$1,200,000
Total annual cost, \$/yr	\$ 44,500,000	\$38,700,000	\$37,900,000	\$33,100,000
SO <sub>2</sub> emissions before control, ton/yr	2,404	2,404	2,404	2,404
SO <sub>2</sub> emissions after control, ton/yr	120	120	120	120
SO <sub>2</sub> emissions Controlled, ton/yr	2,284	2,284	2,284	2,284
Cost effectiveness, \$/ton SO <sub>2</sub> controlled	\$19,500	\$16,900	\$16,600	\$14,500
<p>(1) Capital recovery charges calculated based on 20-year life, a 7% interest rate and a retrofit factor of 1.2. Annual cost without AFUDC is \$18,100/ton SO<sub>2</sub> controlled.</p> <p>(2) Capital recovery charges calculated based on 30-year life, a 7% interest rate and a retrofit factor of 1.2.</p> <p>(3) Capital recovery charges calculated based on 20-year life, a 7% interest rate and a retrofit factor of 1.0.</p> <p>(4) Capital recovery charges calculated based on 30-year life, a 7% interest rate and a retrofit factor of 1.0.</p>				

### 5.1.2 Time Necessary for Compliance (Factor 2)

If a wet FGD system or an SDA system is required by the SIP, Avon Lake Power Plant expects that approximately 5 years would be required to complete installation of such a system after the SIP is fully approved by EPA. If determined to be required, a wet or dry scrubbing system could be installed by 2028.

### 5.1.3 Energy and Non-Air Quality Environmental Impacts (Factor 3)

There are significant energy and solid waste impacts associated with wet limestone FGD systems. New Effluent Limit Guidelines apply to wastewater discharges from wet FGD systems that require expensive and complex treatment systems. However, the impacts are not unacceptable to high capacity factor units and many wet FGD systems have been installed on well utilized coal-fired power plants across the country.

### 5.1.4 Remaining Useful Life (Factor 4)

Unit 9 was commissioned in 1970. Although the unit is about 50 years old, no specific retirement date has been set. Per the Plant's current estimates, the boiler's remaining useful life may be conservatively assumed to be 20 years. See Section 5.1.1 for additional information on remaining useful life of coal units.

## 5.2 Identification of Potentially Available NO<sub>x</sub> Emissions Reduction Options

Several NO<sub>x</sub> control options were considered for application to the Avon Lake Power Plant, including Selective Catalytic Reduction (SCR), Selective Noncatalytic Reduction (SNCR), Powerspan ECO® system, rich reagent injection, natural gas reburn, coal reburn, NOxStar, water injection, LoTOX, PerNOxide, ROFA, and ROTAMIX. These technologies were evaluated for technical feasibility (availability and applicability to Unit 9) based on a review of possible performance, engineering principals, and an assessment of commercial availability. All were eliminated based on technical or practical application issues except for SNCR and SCR technologies. These findings are listed in **Table 5-3**.

**Table 5-3 NOx Control Technologies**

<b>NOx Control Option</b>	<b>Description</b>
<b>Rich reagent injection</b>	Similar to SNCR and does not provide effective NO <sub>x</sub> control at low loads. Only available for cyclone fired boilers. <sup>(1)</sup>
<b>Natural gas reburn</b>	Performance is affected by baseline NO <sub>x</sub> concentration; reburn zone temperature, residence time, and stoichiometry; overfire burnout zone temperature and residence time; and mixing of the reburn fuel with the bulk flue gas. Extensive testing required to make a meaningful prediction of performance. <sup>(1)</sup> Based on very limited, if any, applications, natural gas reburn is not expected to offer a significant emission reduction relative to other options such as an SNCR and SCR. Additionally, the availability of adequate natural gas supply is unlikely.
<b>Coal reburn</b>	Similar to natural gas reburn.
<b>NOxStar <sup>(2)</sup></b>	Uses an ammonia-based reagent and small amounts of hydrocarbon injected to the flue gas at the convective pass of the boiler to reduce NO <sub>x</sub> . Only one full scale demonstration project. An emerging technology that would require extensive design engineering and a long-term full scale demonstration to evaluate technical feasibility, cost, and performance. <sup>(1)</sup>
<b>Water injection <sup>(2)</sup></b>	To date, only bench scale testing on coal firing. Extensive design engineering and testing would be needed to determine scale-up potential, cost and performance. <sup>(1)</sup>
<b>LoTOX <sup>(2)</sup></b>	A low temperature oxidation system that uses ozone to convert NO and NO <sub>2</sub> to N <sub>2</sub> O <sub>5</sub> for eventual removal by a wet scrubber. No known full-scale, coal-fired EGU applications.
<b>PerNOxide <sup>(2)</sup></b>	Uses hydrogen peroxide injected into the duct ahead of the air preheater. Has only been tested on a pilot scale. Extensive design engineering and testing would be needed to determine scale-up potential, cost and performance. <sup>(1)</sup>
<b>ROFA</b>	Rotating opposed overfire air. CFD modelling required to determine performance but expected to be inferior to an SNCR or an SCR.
<b>ROTAMIX</b>	Similar to an SNCR (Proprietary SNCR technology)
<p>(1) Coyote Station Unit 1, North Dakota Regional Haze Second Planning Period Four-Factor Analysis. Sargent &amp; Lundy, May 8, 2019.</p> <p>(2) These are innovative technologies and have not been commercially demonstrated on a large scale utility boiler such as Unit 9. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system.</p>	

SNCR and SCR were selected for further evaluation based on commercial availability and existing applications to coal-fired boilers.

## 5.2.1 Costs of Compliance (Factor 1)

This section presents cost for SNCR and SCR.

### 5.2.1.1 Costs of Compliance - SNCR

There is minimal, salvageable infrastructure remaining from the temporary, demonstration SNCR system. If an SNCR is considered, it should be a new system with adequate performance guarantees. An OEM will not be willing to give any performance guarantees with used equipment. Therefore, a new SNCR system was evaluated for costing purposes.

The capital cost for an SNCR system was estimated using EPA's Air Pollution Cost Control Manual SNCR Cost Calculation Spreadsheet which was updated in 2019.<sup>12</sup> The NOx control offered by an SNCR is expected to be 20% at loads greater than 300 MW, based on experience with a temporary demonstration SNCR system used from 2005 to 2009. At loads below 300 MW, the furnace temperatures are too low to inject urea (i.e., no NOx control can be achieved at these low loads). Future cycling of Unit 9 is expected to be similar to its operation in the 2017 – 2019 time period. Accordingly, SNCR cannot operate at the lower dispatched production levels and no NOx reductions are realized by this technology in this load range. The hourly data show that in 2019, only about 75.36% of the power was generated at loads greater than 300 MW. Based on hourly 2019's loads and emissions, the expected achievable NOx control efficiency is 15.2% on an annual average basis. For the purpose of this analysis, we are evaluating the cost-effectiveness of an SNCR system at a control efficiency of 20% when the unit is at loads greater than 300 MW.

**Table 5-4 Avon Lake Power Plant: Unit 9 SNCR Cost Analysis**

Cost Item	Case A <sup>(1)</sup>	Case B <sup>(2)</sup>
Total Capital Investment, \$	\$13,000,000	\$13,000,000
Annual Costs		
Capital Recovery, \$/yr	\$1,230,000	\$1,050,000
Maintenance, \$/yr	\$195,000	\$195,000
Urea solution <sup>(3)</sup> , \$/yr	\$244,000	\$244,000
Electricity, \$/yr	\$2,200	\$2,200
Fuel, \$/yr	\$2,000	\$2,000
Administrative charges, \$/yr	\$5,900	\$5,900
Total annual cost, \$/yr	\$1,679,100	\$1,499,100
NOx emissions before control, ton/yr	820	820
NOx emissions after control, ton/yr	656	656
NOx emissions removed, ton/yr	164	164
Cost effectiveness, \$/ton NOx controlled	\$10,200	\$9,100
(1) Capital recovery charges calculated based on 20-year life and a 7% interest rate (2) Capital recovery charges calculated based on 30-year life and a 7% interest rate (3) 50% urea solution, \$1.08/gal delivered		

<sup>12</sup> Available at: <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>

The total estimated capital cost of an SNCR is \$13 million (with a 1.0 retrofit factor for a normal retrofit). Unlike FGD and SCR systems, SNCR does not typically pose as many retrofit issues. Annual cost and cost effectiveness results are summarized in **Table 5-4**. Detailed calculations are presented in **Appendix B**. Urea consumption was based on a normalized stoichiometric of 1.0 calculated from Equation 1.17 in EPA's Air Pollution Control Cost Manual and a delivered cost of \$1.08/gallon for 50% urea solution. The total annual cost for SNCR is estimated at about \$1.7 million/yr. The cost effectiveness is \$10,200 per ton of NO<sub>x</sub> controlled (Case A). If the capital recovery is based on a 30-year life and a 7% interest rate, the annual cost of an SNCR is \$1.5 million/yr for a cost effectiveness of \$9,100 per ton NO<sub>x</sub> controlled.

### 5.2.1.2 Costs of Compliance - SCR

The capital cost for SCR was estimated based using EPA's Air Pollution Control Cost Manual SCR Cost Calculation Spreadsheet, which was updated in 2019<sup>13</sup>. The total estimated capital cost is \$229 million. The capital cost is based on a 1.2 retrofit factor to account for the significant site-specific difficulties and space issues present at the plant due to confined footprint and the presence of a DSI/ACI control system for MATS control. In their 2009 study, URS Washington Group estimated the total capital cost of an SCR system on Unit 9 at \$230 million. Escalation of the 2009 capital cost to a 2019 cost based on the Chemical Engineering Plant Cost Index (607.5/521.9) indicates a current capital cost of \$268 million. It should be noted that the URS Washington Group estimated cost escalated to 2019 is significantly greater than that estimated by the Control Cost Manual. However, to be conservative, we are proceeding with the costs developed using the Control Cost Manual.

Annual cost and cost effectiveness results are summarized in **Table 5-5**. Detailed calculations are presented in **Appendix B**.

The total estimated annual cost for an SCR system is \$25.6 million/yr (based on 20-year life, a 7% interest rate and a retrofit factor of 1.2) or \$22.4 million/yr (based on 30-year life, a 7% interest rate and a retrofit factor of 1.2). Capital recovery charges account for a large percentage of the annual costs. Variable annual operating costs are low due to the low annual capacity factor. The cost effectiveness is excessive at \$26,700 per ton of NO<sub>x</sub> controlled. Extremely high costs are attributable to the very low annual capacity factor and the high capital costs associated with SCR.

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<sup>13</sup> Available at: <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>

**Table 5-5 Avon Lake Power Plant: Unit 9 SCR Cost Analysis**

Cost Item	Case A-1 <sup>(1)</sup>	Case A-2 <sup>(2)</sup>	Case B-1 <sup>(3)</sup>	Case B-2 <sup>(4)</sup>
Total Capital Investment, \$	\$229,000,000	\$229,000,000	\$191,000,000	\$191,000,000
Annual Costs				
Capital Recovery <sup>(a)</sup> , \$/yr	\$21,600,000	\$18,500,000	\$18,000,000	\$15,400,000
Maintenance, \$/yr	\$1,100,000	\$1,100,000	\$1,000,000	\$1,000,000
Ammonia, \$/yr	\$100,000	\$100,000	\$100,000	\$100,000
Electricity, \$/yr	\$100,000	\$100,000	\$100,000	\$100,000
Catalyst replacement, \$/yr	\$2,600,000	\$2,600,000	\$2,600,000	\$2,600,000
Administrative charges, \$/yr	\$14,000	\$14,000	\$12,000	\$12,000
Total annual cost, \$/yr	\$25,600,000	\$22,400,000	\$21,800,000	\$19,200,000
NOx emissions before control, ton/yr	1,065	1,065	1,065	1,065
NOx emissions after control (90% control assumed) <sup>(5)</sup> , ton/yr	107	107	107	107
NOx emissions removed, ton/yr	959	959	959	959
Cost effectiveness, \$/ton NOx controlled	\$26,700	\$23,400	\$22,750	\$20,000
<ol style="list-style-type: none"> <li>1. Capital recovery charges calculated based on 20-year life, a 7% interest rate and a retrofit factor of 1.2.</li> <li>2. Capital recovery charges calculated based on 30-year life, a 7% interest rate and a retrofit factor of 1.2.</li> <li>3. Capital recovery charges calculated based on 20-year life, a 7% interest rate and a retrofit factor of 1.0.</li> <li>4. Capital recovery charges calculated based on 30-year life, a 7% interest rate and a retrofit factor of 1.0.</li> <li>5. At a NOx inlet rate of 0.317 lb/MMBtu, a 90% control efficiency results in a NOx outlet emission rate of 0.032 lb/MMBtu which is very low as an annual average value. A more realistic target for outlet NOx would be 0.05 – 0.07 lb/MMBtu. However, for the purposes of this analysis, we are proceeding with a conservatively low NOx outlet estimate of 0.037 lb/MMBtu (90% control).</li> </ol>				

### 5.2.2 Time Necessary for Compliance (Factor 2)

After a final SIP is issued, approximately 2 years would be required to complete installation of an SNCR system and approximately 5 years would be required to complete installation of an SCR system. If determined to be required, either system could be installed by 2028.

### 5.2.3 Energy and Non-Air Quality Environmental Impacts (Factor 3)

There are energy impacts associated with the use of SCR. SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

In addition, there are potential environmental impacts associated with the use of ammonia. There are potential hazards involved in the transportation, handling and storage of ammonia due the possibility of accidental releases. There may also be issues with spent catalyst disposal.

Also, even in the most well-designed units, a certain amount of ammonia slips through the process as unreacted ammonia and is emitted as such through the stack. This ammonia can combine with the nitrate and sulfate in ambient air to form secondary particulate matter, which would result in increased regional haze formation as a consequence of operating the SCR system. Urea utilization by SNCR is expected to be less than 30%. Relatively high ammonia slip and ash contamination by ammonia are possible adverse impacts associated with the use

of an SNCR system. SCR operates with a relatively higher ammonia utilization and lower ammonia slip than SNCR.

#### 5.2.4 Remaining Useful Life (Factor 4)

Unit 9 was commissioned in 1970. Although the unit is almost 50 years old, no specific retirement date has been set. Per the current estimates, the boiler's remaining useful life may be assumed to be 20 years. As discussed previously, a 20-year amortization was used because it has been used historically and is consistent with available guidance, including EPA's Air Pollution Control Cost Manual. The most recent version of the EPA's Air Pollution Control Cost Manual Chapter on SCR (last updated in 2019) includes an example calculation which assumes a 30-year lifetime for SCR (i.e., a 30-year amortization period). However, in the studies and reports cited in EPA's Air Pollution Control Cost Manual, their conclusion that 30 years is possible for an SCR is not based on demonstrated experiences at coal-fired electric generating units. Importantly, EPA's Air Pollution Control Cost Manual otherwise continues to use a 20-year period for costs of supporting and ancillary equipment for SCR. Therefore, best available information indicates a 20-year period is most appropriate for amortizing SCR and SNCR costs. See Section 5.1.1 for additional information on remaining useful life of coal units.

## 6. Additional 5<sup>th</sup> Factor Consideration - Visibility Impacts

The goal of the RHR is to improve the visibility in Class I areas. Accordingly, when evaluating possible emissions reduction projects or programs, it is appropriate to consider the degree to which individual control projects might contribute towards that goal. Although states have a statutory requirement to consider the "4 factors" addressed in **Section 5** of this report, EPA's guidance<sup>14</sup> also allows inclusion by states of a "5<sup>th</sup> factor" which involves consideration of visibility impacts of candidate control options. The fifth factor doesn't change or replace the conclusions reached in the Four Factor Analysis – it provides additional information on the effects of controls as supporting "common sense" information. This section addresses the visibility impacts of current operations as well as the expected visibility improvements for emission control options. As explained below, because the visibility impacts attributable to the Avon Lake Power Plant are negligible, further controls and/or lower emission limits, even if technically and economically feasible, would not yield material visibility benefits at any of the regional Class I.

### 6.1 EPA Guidance Regarding Considerations of Visibility Impacts

The EPA issued "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period"<sup>15</sup> in August 2019. This guidance allows a state, as part of its consideration of emission controls, to include a "5<sup>th</sup> factor" consideration of visibility impacts of candidate control options.

On pages 36 and 37 of this guidance, the EPA notes that concerning the underlying regulation for ascertaining reasonable further progress, the regulation:

*"assumes that the state will consider visibility benefits as part of the analysis. Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered. Because the*

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<sup>14</sup> US EPA; "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" in August 2019. Available at [https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019\\_-\\_regional\\_haze\\_guidance\\_final\\_guidance.pdf](https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf).

*goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal.” . . .*

*“ . . . EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress.”*

Consequently, prediction of a very low impact to Class I visibility impairment from control of certain facility pollutants is appropriate for consideration when evaluating the need for further control of these emissions for Regional Haze Reasonable Progress.

EPA’s 2019 RHR guidance does not specifically state what would constitute an insignificant visibility impact, but the preamble to the 1999 RHR (64 FR 35730) does specify a “no degradation” visibility change if the impact is less than 0.1 deciview. In addition, MANE-VU determined in the first decadal review that a visibility improvement less than 0.1 deciview individual impact does not warrant consideration of additional controls<sup>16</sup>. This amount of visibility change is only about 0.5% of the 2028 glidepath target for Shenandoah National Park and only about 1% of the unadjusted<sup>17</sup> 2064 natural conditions target, so it constitutes a very low value. In the discussion below, the “no degradation” visibility improvement value of 0.1 delta-deciview is referred to as a “benchmark” for considering a low visibility improvement as part of the overall decision process.

Although the consideration of visibility impacts is not necessarily an “off-ramp” for not requiring a candidate control option, the information about the visibility improvement to be realized by an emission control option is useful for the overall decision as to whether the control option should be adopted. Decisions made by states for the First Decadal Review have many examples for which a marginally cost-effective control option was evaluated in conjunction with the expected visibility improvement. In a number of cases for the First Decadal Review<sup>18</sup>, an expected low visibility improvement was considered in conjunction with the cost effectiveness of a control option as part of a final decision not to adopt the control.

Another issue that is sometimes raised in conjunction with visibility impacts is whether they should be cumulatively considered; i.e., added over several Class I areas. This type of metric is not appropriate because changes cannot be perceived in multiple Class I areas by a single observer at a given time; that is, an individual observer cannot perceive an additive improvement at multiple Class I areas. This is similar to asserting that if, say, 4 rain gauges located in different sites each measured an inch of rain in a single day, the total daily rainfall was 4 inches. Therefore, the cumulative approach distorts the visibility analysis because it sums computer-modeled visibility impacts at multiple locations at multiple (and usually different) times. In addition, the approach is irrational because it treats a single source of regional haze differently simply depending on the number of Class I areas that happen to be located around the source at varying distances, irrespective of their size or spatial distribution. Therefore, the

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<sup>16</sup> 77 FR 17367 (March 26, 2012).

<sup>17</sup> Note that the glidepaths for natural conditions can be adjusted upward by each state for uncontrollable internationally-caused haze.

<sup>18</sup> Several cases are discussed as part of a comment listed in the Wyoming final rule for a partial Federal Implementation Plan for Wyoming in the January 30, 2014 Federal Register (79 FR 5032). On page 5122, the following discussion is presented:

‘EPA has determined in other states that visibility improvements... are too small or inconsequential to justify additional pollution controls. See 77 FR 24794 (0.27 deciview improvement termed “small” and did not justify additional pollution controls in New York); 77 FR 11879, 11891 (0.043 to 0.16 delta deciview improvements considered “very small additional visibility improvements” that did not justify NOx controls in Mississippi); 77 FR 18052, 18066 (agreeing with Colorado’s determination that “low visibility improvement (under 0.2 delta deciview)” did not justify SCR for Comanche units)). Tellingly, the “low visibility improvements” that Colorado found at the Comanche units not to justify post-combustion NOx controls, as agreed to by EPA, were 0.17 and 0.14 delta deciview. 77 FR 18066. In Montana, where EPA issued a regional haze FIP directly, it found that a 0.18 delta deciview improvement to be a “low visibility improvement” that “did not justify proposing additional controls” for SO<sub>2</sub> on the source. 77 FR 23988, 24012.’

cumulative approach is misleading and tends to exaggerate the visibility impact of a given emission source.

## **6.2 Class I Areas Near Avon Lake Power Plant**

Class I areas in the eastern United States near Ohio are shown in **Figure 6-1**. The closest Class I areas to the Avon Lake Power Plant are Dolly Sods and Otter Creek Wilderness Areas in West Virginia which are 350 km from the plant. Other Class I areas are more than 400 km from the Avon Lake Power Plant.

**Figure 6-1 Class I Areas in the Vicinity of Avon Lake Power Plant**



### 6.3 Lake Michigan Air Directors Consortium (LADCO)

The state of Ohio is a member of the Lake Michigan Air Directors Consortium (LADCO) Regional Planning Organization. LADCO assists its member states by conducting modeling analyses, including photochemical grid modeling, to assess visibility impacts from emission sources. This is especially helpful in determining the haze impact of the current emissions from sources being considered for SO<sub>2</sub> and NO<sub>x</sub> controls. It is reasonable to consider modeled haze impacts in addition to control costs to determine whether a marginally cost-effective control option is likely to result in a non-trivial improvement in visibility. As discussed above, a 0.1 deciview change to the worst 20% impaired days is a reasonable rule-of-thumb for assessing the effectiveness of a control option to reduce haze.

A modeling result for this assessment is best obtained for a photochemical grid modeling analysis for which the source's emissions are "tagged" for purposes of determining the sulfate and nitrate haze contributions at each Class I area under consideration. Then, the results of partial controls of either SO<sub>2</sub> or NO<sub>x</sub> can be linearly scaled due to the relatively large distances to the Class I areas.

It is our understanding that LADCO is currently conducting photochemical grid modeling that will assist member states to assess impacts from sources in states and industry sectors (e.g., electric generating stations). As of March 2021, the LADCO modeling has not been completed. However, we expect that when the modeling results are available, they will be consistent with independent modeling assessments that have already been completed, as discussed below.

Due to widespread use of photochemical grid models such as CAMx by every other Regional Planning Organization in the country, the next sub-section discusses available CAMx modeling for some Ohio EGUs conducted by the southeastern states Regional Planning Organization, VISTAS / SESARM.

### 6.4 VISTAS CAMx Modeling Analysis

The impact to Class I area visibility of hypothetical reductions to SO<sub>2</sub> and NO<sub>x</sub> emissions can be determined by analyzing the results of visibility modeling conducted by the VISTAS / SESARM<sup>19</sup> Regional Planning Organization that included emissions for some Ohio power plants. The VISTAS modeling was conducted by Alpine Geophysics and utilized advanced CAMx modeling including modeling particulate matter simulations and source apportionment studies. Determinations of the haze contributions of specified large sources was accomplished by "tagging" the selected sources for determining their contribution to impairment at each Class I area of interest. The tagged sources included the Conesville and Cardinal Power Plants in central Ohio. The results of VISTAS modeling analysis of Conesville and Cardinal total emissions can be used, with emissions scaling, to estimate the visibility impacts of the potential SO<sub>2</sub> and NO<sub>x</sub> emission control options on Avon Lake Power Plant Unit 9's emissions. Substantial conservatism is inherent in this approach as these Southern Ohio plants are approximately two-thirds of the distance to the target Class I receptors as compared to Avon Lake.

Visibility impairment is commonly expressed using two parameters to characterize the visibility impairment:

- **Light Extinction ( $b_{ext}$ )** is the reduction in light due to scattering and absorption as it passes through the atmosphere. Light extinction is directly proportional to pollutant

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<sup>19</sup> "VISTAS" is an acronym for Visibility Improvement-State and Tribal Association of the Southeast and "SESARM" stands for Southeastern States Air Resource Managers, Inc. Their web site for Regional Haze Rule modeling results is <https://www.metro4-sesarm.org/content/vistas-regional-haze-program>.

particulate and aerosol concentrations in the air and is expressed in units of inverse megameters or  $Mm^{-1}$ .

- **Deciview (DV)** is a unitless metric of haze which is proportional to the logarithm of the light extinction. Deciview correlates to a person's perception of a visibility change, with a change of 1 deciview being barely perceptible. The "no degradation" value of 0.1 DV stated in the 1999 Regional Haze Rule is only 10% of this perceptibility threshold.

Both metrics are helpful in understanding changes to visibility impairment, but while the deciview is the best parameter to relate the significance of a perceived visibility change, modeling produces results in the form of light extinction using the new IMPROVE equation that converts particulate concentrations to visibility impairment.

In response to comments received from the Federal Land Managers for Ohio's draft State Implementation Plan submittal earlier in 2021, the Ohio EPA has requested that the conversion between deciviews and extinction should reference the natural conditions endpoint visibility conditions. Ohio has indicated that it is permissible to reference the natural conditions endpoint adjusted for international haze contributions. These adjusted endpoints are available from EPA's 2019 visibility modeling document<sup>20</sup>, Appendix E.

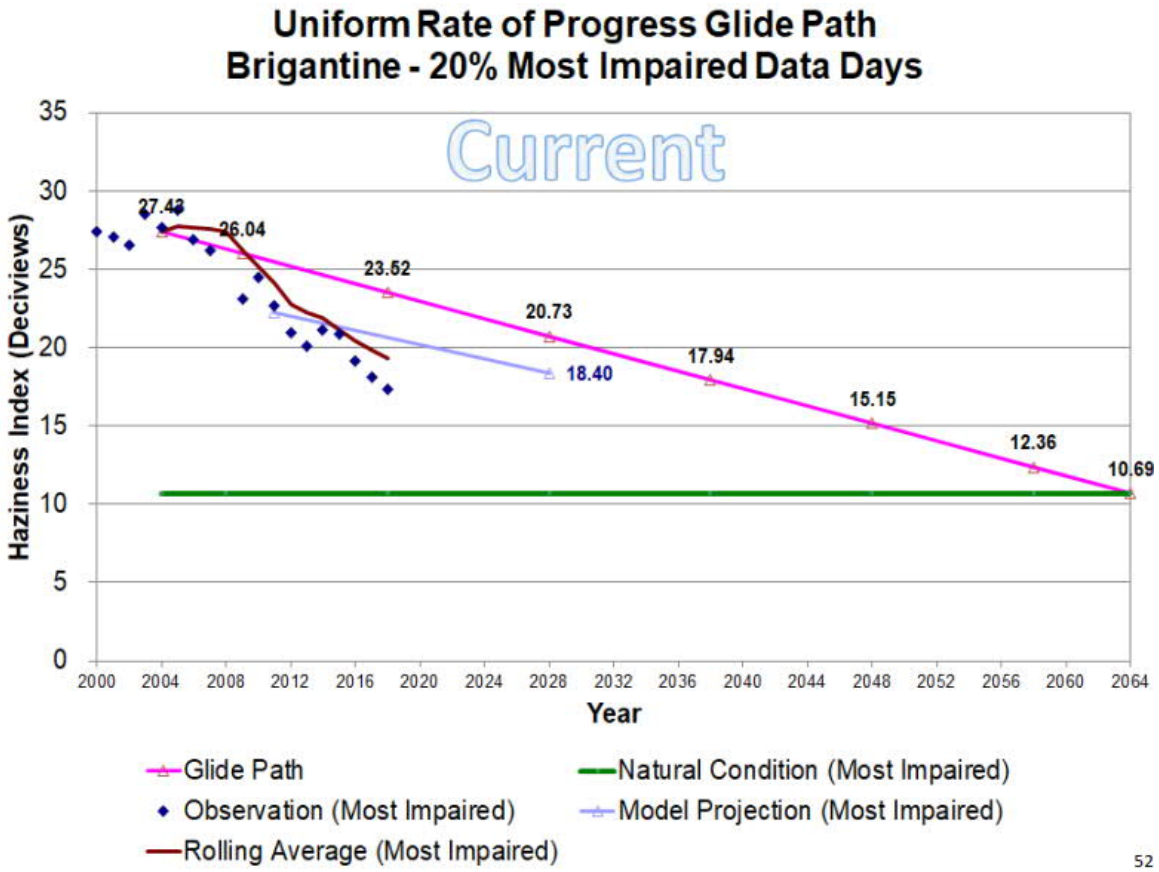
A review of the natural conditions endpoint deciviews published by EPA, adjusted for the influence of international contributions to haze, indicates that the cleanest background is at Dolly Sods and Otter Creek Wilderness Areas, with a deciview value of 11.07. The visibility metrics converter available at <https://vista.cira.colostate.edu/Improve/haze-metrics-converter/> can be used to determine the extinction in inverse megameters for a deciview value of 11.07, as well as 10.97 and 11.17 (0.1 dv increments). It turns out that at that deciview level, a change of 0.1 dv is equivalent to an extinction change of  $0.3 Mm^{-1}$ . This conversion is used in the discussion provided below.

Charts shown in **Figure 6-2** and **6-3** are taken from the VISTAS Regional Haze modeling project update (webinar) updated on September 10, 2020 (after being originally presented on May 20, 2020). They show, in units of deciview, the actual visibility measurements and projected modeling results of visibility for most impaired days at the Brigantine Wilderness Area and Dolly Sods Wilderness Area where the tagged power plants (Conesville and Cardinal) have the greatest impacts.

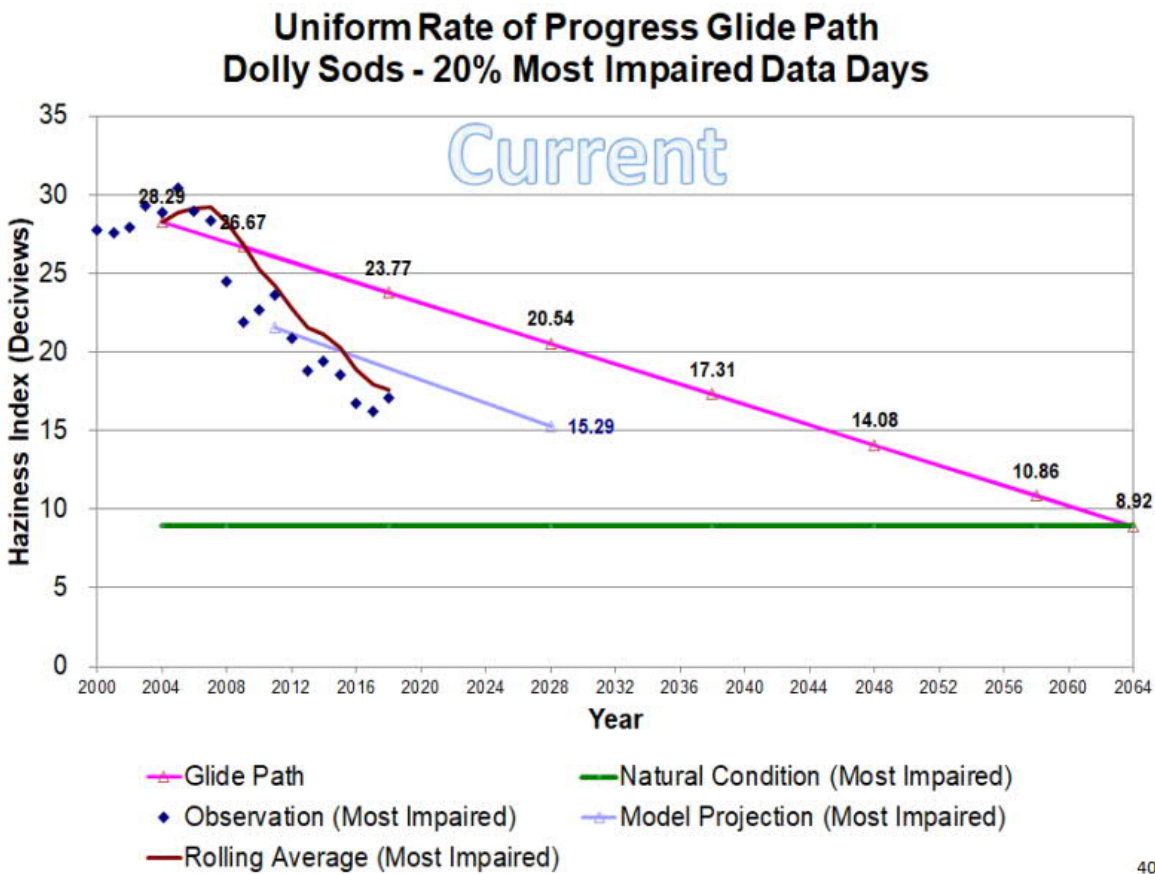
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<sup>20</sup> Available at [https://www.epa.gov/sites/production/files/2019-10/documents/updated\\_2028\\_regional\\_haze\\_modeling-tsd-2019\\_0.pdf](https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf).

**Figure 6-2 Visibility Trends at Brigantine Wilderness Area**



**Figure 6-3 Visibility Trends at Dolly Sods Wilderness Area**



**Figure 6-2** and **6-3** show that actual visibility measurements (the diamonds) confirm a strong trend of improved visibility in the past 10 years from about 27 DV to about 17 DV in Brigantine WA and from 28 DV to 16 DV in Dolly Sods WA. These rates of actual improvement are much faster than the RHR target to maintain a “uniform rate of progress” or “glide path” (the pink line), which could be revised to a less-steep revised glide path to account for internationally-caused haze. However, VISTAS believe that since the Class I areas in this region are so far ahead of projections, that refinement is not necessary at this time.<sup>21</sup> Additionally, VISTAS modeling of the expected emissions reductions in the coming years (on-the-books / on-the-way controls) projects (the blue line) that visibility should continue to significantly improve, reaching 18.4 DV and 15.3 DV by the next RHR milestone year of 2028 for Brigantine and Dolly Sods, respectively. These charts show that visibility in these Class I areas is currently running at least 10 to 20 years ahead of the RHR targets and is expected to continue to do so. VISTAS modeling of other regional Class I areas shows very similar trends and all areas are far ahead of their glide path targets. Therefore, no additional emissions reductions at any regional facilities, beyond those already planned, are needed to continue to meet the RHR interim goals.

**6.5 Impact of Potential SO<sub>2</sub> and NO<sub>x</sub> Emission Reductions**

The VISTAS modeling used 2011 actual annual emissions, and these values can be scaled to current representative emissions for the Avon Lake Power Plant with reductions to account for impacts (improvements) resulting from potential NO<sub>x</sub> and SO<sub>2</sub> controls options. Ohio EPA has stipulated that 2017 through 2019 average emissions should be considered as a representative

<sup>21</sup> VISTAS/SESARM response during Q&A of VISTAS Regional Haze modeling webinar presented on May 20, 2020.

baseline for this analysis and effects of potential NO<sub>x</sub> and SO<sub>2</sub> controls options were applied to these baseline emissions. The Avon Lake Power Plant's controlled emissions of NO<sub>x</sub> and SO<sub>2</sub> can be compared to modeled emissions for Conesville and Cardinal Stations to develop conservative estimates of visibility improvements of SO<sub>2</sub> and NO<sub>x</sub> emissions controls as shown in **Appendix C**. Because the Avon Lake Power Plant is 350 km from the Dolly Sods WA and Cardinal is only 150 km from the Dolly Sods WA, visibility estimates based on the Cardinal Station are already very conservative. Also, because the Avon Lake Power Plant is 550 km from the Brigantine WA and Cardinal Station is 350 km from the Brigantine WA, visibility estimates based on Cardinal Station's impacts are expected to be very conservative. With linear scaling and application of potential NO<sub>x</sub> and SO<sub>2</sub> controls, this results in haze improvement values at Class I areas based upon the VISTAS modeling as shown in **Table 6-1** and **6-2**. Using the VISTAS modeling data, one can calculate the visibility improvement for different emissions scenarios by taking the ratio of the emission reduction to the total emissions modeled (See **Appendix C** for details). **Tables 6-1** and **6-2** present the visibility improvement for wet FGD (or SDA) and SNCR and wet FGD (or SDA) and SCR, respectively.

**Table 6-1 Visibility Improvement for Wet FGD or SDA and SNCR**

Class I Areas Nearest to the Avon Lake Power Plant	Total Haze Improvement from SO <sub>2</sub> Emission Reduction		Total Haze Improvement from NO <sub>x</sub> Emission Reduction	
	Mm <sup>-1</sup>	DV*	Mm <sup>-1</sup>	DV*
Brigantine WA	0.0438	0.0146	0.00047	0.00016
Dolly Sods WA	0.1797	0.0599	0.00027	0.00009
James River Face WA	0.1200	0.0400	0.00033	0.00011
Mammoth Cave NP	0.0380	0.0127	0.00060	0.00020
Otter Creek WA	0.1678	0.0559	0.00033	0.00011
Shenandoah NP	0.1598	0.0533	0.00073	<b>0.00024</b>

\* Potential Improvement in DV is listed for the 20% most impaired days for each Class I area. Conversion between deciviews and extinction is based upon the discussion above: 0.1 dv is equivalent to 0.3 Mm<sup>-1</sup> for extinction.

**Table 6-2 Visibility Improvement for Wet FGD or SDA and SCR**

Class I Areas Nearest to the Avon Lake Power Plant	Total Haze Improvement from SO <sub>2</sub> Emission Reduction		Total Haze Improvement from NO <sub>x</sub> Emission Reduction	
	Mm <sup>-1</sup>	DV*	Mm <sup>-1</sup>	DV*
Brigantine WA	0.0438	0.0146	0.00273	0.00091
Dolly Sods WA	0.1797	0.0599	0.00156	0.00052
James River Face WA	0.1200	0.0400	0.00194	0.00065
Mammoth Cave NP	0.0380	0.0127	0.00351	0.00117
Otter Creek WA	0.1678	0.0559	0.00194	0.00065
Shenandoah NP	0.1598	0.0533	0.00427	<b>0.00142</b>

\* Potential Improvement in DV is listed for the 20% most impaired days for each Class I area. Conversion between deciviews and extinction is based upon the discussion above: 0.1 dv is equivalent to 0.3 Mm<sup>-1</sup> for extinction.

In **Table 6-1**, the highest incremental visibility benefits modeled for SO<sub>2</sub>, based on the emission controls discussed in **Section 5.1**, are 0.060 DV, well below the "no degradation" benchmark of

0.1 DV and are only 0.39% of projected 2028 conditions for visibility during the 20% most impaired days at Dolly Sods Wilderness Area (15.29 DV). The highest incremental visibility benefits modeled for NO<sub>x</sub>, based on the SCR emission controls discussed in **Section 5.2 (Table 5-5)**, are 0.0014 DV, well below the “no degradation” benchmark of 0.1 DV and only 0.0077% of projected 2028 visibility during the 20% most impaired days at the Brigantine WA (18.40 DV). Therefore, the fifth factor results indicate imperceptible improvements from controls evaluated in this analysis. Accordingly, consideration of additional controls for Unit 9 at the Avon Lake Power Plant, using visibility impacts as one element of the decision process, strongly suggests no benefit to further visibility progress.

## 7. Conclusion

At the Avon Lake Power Plant, Unit 9’s actual annual emissions of SO<sub>2</sub> have been reduced between 2006-2008 (indicative of the baseline used during the first RHR planning period) and 2017-2019 by 92% and emissions of NO<sub>x</sub> have been reduced by 79%. Potential SO<sub>2</sub> emissions are limited by adoption of recent SO<sub>2</sub> NAAQS limits. At the 2017-2019 emission rates, estimated visibility impacts attributable to Unit 9 are well below the 0.1 DV “no degradation” benchmark. In addition, these Class I areas are currently running at least 10 to 20 years ahead of the RHR glide path targets and are expected to continue to do so.

Wet limestone FGD and an SDA are both technically feasible options to provide additional SO<sub>2</sub> emission reductions at Unit 9. However, due to the high capital cost and low annual capacity factor for Unit 9, the annual cost is very high at \$22,600 (wet FGD) and \$19,500 (SDA) per ton of SO<sub>2</sub> controlled. In addition, the visibility benefits of additional SO<sub>2</sub> controls are negligible.

SNCR is a technically feasible option to provide an additional 20% NO<sub>x</sub> emission reduction. However, the cost is excessive at \$10,200 per ton of NO<sub>x</sub> controlled. SCR is also a technically feasible option to provide additional NO<sub>x</sub> emission reductions. However, due to the high capital cost and low annual capacity factor for Unit 9, the cost is very high at \$26,700 per ton of NO<sub>x</sub> controlled. In addition, the incremental visibility benefits of both SNCR and SCR are negligible.

Therefore, options for further SO<sub>2</sub> and NO<sub>x</sub> emission controls for Avon Lake Power Plant’s Unit 9 are not cost effective. Ohio EPA can demonstrate reasonable further progress for Avon Lake Power Plant’s Unit 9 by the significant reductions in actual emissions and projected emissions that remain relatively unchanged. Additionally, this report shows that controls not only are very high cost but have negligible visibility benefits. Together, the considerations of high cost of controls and very low visibility improvement can support a decision not to require additional SO<sub>2</sub> and NO<sub>x</sub> controls on Unit 9.

**Appendix A**  
**Ohio EPA Four-Factor Analysis Request**

# Regional Haze Update

June 29, 2020

Bob Hodanbosi  
Chief, Division of Air Pollution Control

Jennifer Van Vlerah  
Assistant Chief, Division of Air Pollution Control



# Avon Lake (B012)

- Q/d = 32 (2016 emissions)
- Operational restrictions in 2016
  - still a Q/d of 7 using 2019 emissions
- SO<sub>2</sub>
  - 2019 emission rate (0.7 lb/mmBTU) does not meet U.S. EPA guidance for effectively-controlled
  - 2017 Title V permit indicates Activated Carbon Injection and Dry Sorbent Injection Systems were installed to control mercury and HCl for compliance with MATS, as a bridge until the natural gas project is completed
    - may have co-benefit of SO<sub>2</sub> removal, but are not shown as removing SO<sub>2</sub> in STARS2
- NO<sub>x</sub>
  - SNCR (20% removal) – does not meet U.S. EPA guidance for effectively controlled



**Appendix B**  
**Emission Control Cost Estimates**

**Appendix B Table B-1: Wet Flue Gas Desulfurization Cost**

Variable	Designation	Units	Value	Calculation
EPC Project?			<input checked="" type="checkbox"/> TRUE	
Wastewater Treatment		Phys Chem-Biological		
Unit Size	A	(MW)	652	<--- User Input (Greater than 100 MW)
Site elevation	A-1	(ft)	607	
Elevation factor	A-2		1.024	See draft EPA Control Cost Manual
Retrofit Factor	B		1.20	1.0 for an average retrofit. The URS Washington Group Study of 2009 estimated the total capital cost of a wet FGD system at \$389 million. Escalation of the URS capital cost from 2009 estimate to a 2019 cost based on the Chemical Engineering Plant Cost Index (607.5/521.9) indicates a current capital cost of \$453 million.
Heat Rate	C	(Btu/kWh)	8991	<--- User Input, EPA Air Markets Program Data, see Table 4-1
SO2 Rate	D	(lb/MMBtu)	0.71	<--- User Input 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1 of the report.
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.899	C/10000
Heat Input	H	(Btu/hr)	5.86E+09	A*C*1000
Capacity Factor	I	(%)	13.10	<--- User Input 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Operating SO2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Limestone Rate	K	(ton/hr)	4	17.52*A*D*G/2000 (Based on 95% removal)
Design Waste Rate	L	(ton/hr)	7	1.811*K (Based on 95% removal)
Aux Power Include in VOM? <input checked="" type="checkbox"/>	M	(%)	1.18	(1.12e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	47	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	(\$/ton)	30	<--- User Input
Waste Disposal Cost	Q	(\$/ton)	30	<--- User Input
Aux Power Cost	R	(\$/kWh)	0.025	<--- User Input
Makeup Water Cost	S	(\$/kgal)	1.0	<--- User Input
Operating Labor Rate	T	(\$/hr)	60	<--- User Input (Labor cost including all benefits)

**Appendix B Table B-1: Wet Flue Gas Desulfurization Cost**

<b>Costs are all based on 2016 dollars (except for adjustment of total project cost to 2019)</b>		
<b>Capital Cost Calculation</b>	<b>Cost</b>	<b>Comments</b>
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
$BMF\ 584000*(B)*((F*G)^{0.6})*((D/2)^{0.02})*(A^{0.716})$	\$ 70,278,000	Base absorber island cost x A-2
$BMF\ 202000*(B)*((D*G)^{0.3})*(A^{0.716})$	\$ 21,975,000	Base reagent preparation cost
$BMV\ 106000*(B)*((D*G)^{0.45})*(A^{0.716})$	\$ 10,792,000	Base waste handling cost
$BME\ 1070000*(B)*((F*G)^{0.4})*(A^{0.716})$	\$ 132,962,000	Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, minor WWT, etc... x A-2
BMV If type is Bio-Chem, then $10600000*(B)*A/500^{0.6}$ , else 0	\$ 14,916,044	Base wastewater treatment facility, beyond minor physical/chemical treatment
$BM\ BMR + BMF + BMW + BMB + BMWW$	\$ 250,923,044	Total base module cost including retrofit factor
$BM\ (\$/kW) =$		385 Base cost per kW
<b>Total Project Cost</b>		
A1 = 10% of BM	\$ 25,092,000	Engineering and Construction Management costs
A2= 10% of BM	\$ 25,092,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc....
A3 = 10% of BM	\$ 25,092,000	Contractor profit and fees
<b>CECC (\$) = BM + A1 + A2 + A3</b>	<b>\$ 326,199,044</b>	Capital, engineering and construction cost subtotal
<b>CECC (\$/kW) =</b>	<b>500</b>	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	\$ 16,310,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' (\$) - Includes Owner's Costs = CECC + B1	\$ 342,509,044	Total project cost without AFUDC
<b>TPC' (\$/kW) - Includes Owner's Costs</b>	<b>525</b>	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$ 34,251,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC+B1	\$ 54,068,000	EPC fees of 15%
529		
<b>TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1</b>	<b>\$ 483,000,000</b>	Total project cost escalated to 2019, 607.5/541.7 based on Chemical Engineering Plant Cost Index for 2019/2016
<b>TPC (\$/kW) = Includes Owner's Costs and AFUDC</b>	<b>741</b>	Total project cost per kW

**Appendix B Table B-1: Wet Flue Gas Desulfurization Cost**

Fixed O&M Cost			
FOMO (\$/kW yr) = (if MW>500 then 16 additional operators, else 12 operators)*2080*T/(A*1000)	\$	3.06	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)	\$	4.81	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$	0.15	Fixed O&M additional administrative labor costs
FOMWW (\$/kW yr) =		0	Fixed O&M costs for wastewater treatment facility
<b>FOM (\$/kW yr) = FOMO +FOMM+FOMA+ FOMWW</b>	<b>\$</b>	<b>8.02</b>	<b>Total Fixed O&amp;M costs</b>
Variable O&M Cost			
VOMR (\$/MWh) = K*P/(A*J)/98	\$	0.17	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = L*Q/(A*J)/98	\$	0.30	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	\$	0.30	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	\$	0.07	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	\$	0.17	Variable O&M costs for wastewater treatment facility
<b>VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW</b>	<b>\$</b>	<b>1.01</b>	<b>Total Variable O&amp;M costs</b>
Annual Capacity Factor =	<b>13.10%</b>		
Annual MWh =	748,172		
Annual Heat Input MMBtu =	6,726,692		
Annual Tons SO2 Created =	2,404	at 100% S conversion	
Annual Tons SO2 Removed =	2,284	at removal efficiency = 95%	
Annual Tons SO2 Emission =	120		
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.036	Value is BELOW a 0.06 floor rate	
Annual Capital Recovery Factor =	<b>0.0944</b>	Wet FGD	7% interest and 20 years useful life
Annual Capital Cost (Including AFUDC), \$ =	45,600,000		
Annual FOM Cost, \$ =	5,200,000		
Annual VOM Cost, \$ =	760,000		
Total Annual FGD Cost, \$ =	51,600,000		
Capital Cost, \$/MWh =	60.95		
FOM Cost, \$/MWh =	6.95		
VOM Cost, \$/MWh =	1.02		
Total FGD Cost, \$/MWh =	68.91		
Capital Cost, \$/ton =	19,965		
FOM Cost, \$/ton =	2,277		
VOM Cost, \$/ton =	333		
Avon Lake Power Plant	Total FGD Cost, \$/ton =	22,600	per ton SO2 removed

**Appendix B Table B-2: Wet Flue Gas Desulfurization Cost**

Variable	Designation	Units	Value	Calculation
EPC Project?			<input checked="" type="checkbox"/> TRUE	
Wastewater Treatment		Phys Chem-Biological		
Unit Size	A	(MW)	652	<--- User Input (Greater than 100 MW)
Site elevation	A-1	(ft)	607	
Elevation factor	A-2		1.024	See draft EPA Control Cost Manual
Retrofit Factor	B		1.20	1.0 for an average retrofit. The URS Washington Group Study of 2009 estimated the total capital cost of a wet FGD system at \$389 million. Escalation of the URS capital cost from 2009 estimate to a 2019 cost based on the Chemical Engineering Plant Cost Index (607.5/521.9) indicates a current capital cost of \$453 million.
Heat Rate	C	(Btu/kWh)	8991	<--- User Input, EPA Air Markets Program Data, see Table 4-1
SO2 Rate	D	(lb/MMBtu)	0.71	<--- User Input 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1 of the report.
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.899	C/10000
Heat Input	H	(Btu/hr)	5.86E+09	A*C*1000
Capacity Factor	I	(%)	13.10	<--- User Input 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Operating SO2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Limestone Rate	K	(ton/hr)	4	17.52*A*D*G/2000 (Based on 95% removal)
Design Waste Rate	L	(ton/hr)	7	1.811*K (Based on 95% removal)
Aux Power Include in VOM? <input checked="" type="checkbox"/>	M	(%)	1.18	$(1.12e^{(0.155*D)}) * F * G$
Makeup Water Rate	N	(1000 gph)	47	$(1.674 * D + 74.68) * A * F * G / 1000$
Limestone Cost	P	(\$/ton)	30	<--- User Input
Waste Disposal Cost	Q	(\$/ton)	30	<--- User Input
Aux Power Cost	R	(\$/kWh)	0.025	<--- User Input
Makeup Water Cost	S	(\$/kgal)	1.0	<--- User Input
Operating Labor Rate	T	(\$/hr)	60	<--- User Input (Labor cost including all benefits)

**Appendix B Table B-2: Wet Flue Gas Desulfurization Cost**

<b>Costs are all based on 2016 dollars (except for adjustment of total project cost to 2019)</b>		
<b>Capital Cost Calculation</b>	<b>Cost</b>	<b>Comments</b>
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
$BMF\ 584000*(B)*((F*G)^{0.6})*((D/2)^{0.02})*(A^{0.716})$	\$ 70,278,000	Base absorber island cost x A-2
$BMF\ 202000*(B)*((D*G)^{0.3})*(A^{0.716})$	\$ 21,975,000	Base reagent preparation cost
$BMV\ 106000*(B)*((D*G)^{0.45})*(A^{0.716})$	\$ 10,792,000	Base waste handling cost
$BME\ 1070000*(B)*((F*G)^{0.4})*(A^{0.716})$	\$ 132,962,000	Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, minor WWT, etc... x A-2
BMV If type is Bio-Chem, then $10600000*(B)*A/500^{0.6}$ , else 0	\$ 14,916,044	Base wastewater treatment facility, beyond minor physical/chemical treatment
$BM\ BMR + BMF + BMW + BMB + BMWW$	\$ 250,923,044	Total base module cost including retrofit factor
$BM\ (\$/kW) =$		385 Base cost per kW
<b>Total Project Cost</b>		
A1 = 10% of BM	\$ 25,092,000	Engineering and Construction Management costs
A2= 10% of BM	\$ 25,092,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc....
A3 = 10% of BM	\$ 25,092,000	Contractor profit and fees
<b>CECC (\$) = BM + A1 + A2 + A3</b>	<b>\$ 326,199,044</b>	Capital, engineering and construction cost subtotal
<b>CECC (\$/kW) =</b>	<b>500</b>	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	\$ 16,310,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' (\$) - Includes Owner's Costs = CECC + B1	\$ 342,509,044	Total project cost without AFUDC
<b>TPC' (\$/kW) - Includes Owner's Costs</b>	<b>525</b>	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$ 34,251,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC+B1	\$ 54,068,000	EPC fees of 15%
529		
<b>TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1</b>	<b>\$ 483,000,000</b>	Total project cost escalated to 2019, 607.5/541.7 based on Chemical Engineering Plant Cost Index for 2019/2016
<b>TPC (\$/kW) = Includes Owner's Costs and AFUDC</b>	<b>741</b>	Total project cost per kW

## Appendix B Table B-2: Wet Flue Gas Desulfurization Cost

Fixed O&M Cost			
FOMO (\$/kW yr) = (if MW>500 then 16 additional operators, else 12 operators)*2080*T/(A*1000)	\$	3.06	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)	\$	4.81	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$	0.15	Fixed O&M additional administrative labor costs
FOMWW (\$/kW yr) =		0	Fixed O&M costs for wastewater treatment facility
<b>FOM (\$/kW yr) = FOMO +FOMM+FOMA+ FOMWW</b>	<b>\$</b>	<b>8.02</b>	<b>Total Fixed O&amp;M costs</b>
Variable O&M Cost			
VOMR (\$/MWh) = K*P/(A*J)/98	\$	0.17	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = L*Q/(A*J)/98	\$	0.30	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	\$	0.30	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	\$	0.07	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	\$	0.17	Variable O&M costs for wastewater treatment facility
<b>VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW</b>	<b>\$</b>	<b>1.01</b>	<b>Total Variable O&amp;M costs</b>
Annual Capacity Factor =	<b>13.10%</b>		
Annual MWh =	748,172		
Annual Heat Input MMBtu =	6,726,692		
Annual Tons SO2 Created =	2,404	at 100% S conversion	
Annual Tons SO2 Removed =	2,284	at removal efficiency = 95%	
Annual Tons SO2 Emission =	120		
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.036	Value is BELOW a 0.06 floor rate	
Annual Capital Recovery Factor =	<b>0.0806</b>	Wet FGD	7% interest and 30 years useful life
Annual Capital Cost (Including AFUDC), \$ =	38,900,000		
Annual FOM Cost, \$ =	5,200,000		
Annual VOM Cost, \$ =	760,000		
Total Annual FGD Cost, \$ =	44,900,000		
Capital Cost, \$/MWh =	51.99		
FOM Cost, \$/MWh =	6.95		
VOM Cost, \$/MWh =	1.02		
Total FGD Cost, \$/MWh =	59.96		
Capital Cost, \$/ton =	17,032		
FOM Cost, \$/ton =	2,277		
VOM Cost, \$/ton =	333		
Total FGD Cost, \$/ton =	19,600	per ton SO2 removed	

Avon Lake Power Plant

Four Factor Analysis

Appendix B

Wet FGD(1.2\_30yr)

Revised March 2021

**Appendix B Table B-3: Wet Flue Gas Desulfurization Cost**

Variable	Designation	Units	Value	Calculation
EPC Project?			<input checked="" type="checkbox"/> TRUE	
Wastewater Treatment		Phys Chem-Biological		
Unit Size	A	(MW)	652	<--- User Input (Greater than 100 MW)
Site elevation	A-1	(ft)	607	
Elevation factor	A-2		1.024	See draft EPA Control Cost Manual
Retrofit Factor	B		1.00	1.0 for an average retrofit. The URS Washington Group Study of 2009 estimated the total capital cost of a wet FGD system at \$389 million. Escalation of the URS capital cost from 2009 estimate to a 2019 cost based on the Chemical Engineering Plant Cost Index (607.5/521.9) indicates a current capital cost of \$453 million.
Heat Rate	C	(Btu/kWh)	8991	<--- User Input, EPA Air Markets Program Data, see Table 4-1
SO2 Rate	D	(lb/MMBtu)	0.71	<--- User Input 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1 of the report.
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.899	C/10000
Heat Input	H	(Btu/hr)	5.86E+09	A*C*1000
Capacity Factor	I	(%)	13.10	<--- User Input 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Operating SO2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Limestone Rate	K	(ton/hr)	4	17.52*A*D*G/2000 (Based on 95% removal)
Design Waste Rate	L	(ton/hr)	7	1.811*K (Based on 95% removal)
Aux Power Include in VOM? <input checked="" type="checkbox"/>	M	(%)	1.18	(1.12e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	47	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	(\$/ton)	30	<--- User Input
Waste Disposal Cost	Q	(\$/ton)	30	<--- User Input
Aux Power Cost	R	(\$/kWh)	0.025	<--- User Input
Makeup Water Cost	S	(\$/kgal)	1.0	<--- User Input
Operating Labor Rate	T	(\$/hr)	60	<--- User Input (Labor cost including all benefits)

**Appendix B Table B-3: Wet Flue Gas Desulfurization Cost**

<b>Costs are all based on 2016 dollars (except for adjustment of total project cost to 2019)</b>		
<b>Capital Cost Calculation</b>	<b>Cost</b>	<b>Comments</b>
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
$BMF\ 584000*(B)*((F*G)^{0.6})*((D/2)^{0.02})*(A^{0.716})$	\$ 58,565,000	Base absorber island cost x A-2
$BMF\ 202000*(B)*((D*G)^{0.3})*(A^{0.716})$	\$ 18,313,000	Base reagent preparation cost
$BMV\ 106000*(B)*((D*G)^{0.45})*(A^{0.716})$	\$ 8,993,000	Base waste handling cost
$BME\ 1070000*(B)*((F*G)^{0.4})*(A^{0.716})$	\$ 110,801,000	Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, minor WWT, etc... x A-2
BMV If type is Bio-Chem, then $10600000*(B)*A/500^{0.6}$ , else 0	\$ 12,430,037	Base wastewater treatment facility, beyond minor physical/chemical treatment
$BM\ BMR + BMF + BMW + BMB + BMWW$	\$ 209,102,037	Total base module cost including retrofit factor
$BM\ (\$/kW) =$		321 Base cost per kW
<b>Total Project Cost</b>		
A1 = 10% of BM	\$ 20,910,000	Engineering and Construction Management costs
A2= 10% of BM	\$ 20,910,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc....
A3 = 10% of BM	\$ 20,910,000	Contractor profit and fees
<b>CECC (\$) = BM + A1 + A2 + A3</b>	<b>\$ 271,832,037</b>	Capital, engineering and construction cost subtotal
<b>CECC (\$/kW) =</b>	<b>417</b>	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	\$ 13,592,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
$TPC' (\$) - \text{Includes Owner's Costs} = CECC + B1$	\$ 285,424,037	Total project cost without AFUDC
<b>TPC' (\$/kW) - Includes Owner's Costs</b>	<b>438</b>	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$ 28,542,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC+B1	\$ 45,056,000	EPC fees of 15%
529		
<b>TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1</b>	<b>\$ 403,000,000</b>	Total project cost escalated to 2019, 607.5/541.7 based on Chemical Engineering Plant Cost Index for 2019/2016
<b>TPC (\$/kW) = Includes Owner's Costs and AFUDC</b>	<b>618</b>	Total project cost per kW

**Appendix B Table B-3: Wet Flue Gas Desulfurization Cost**

Fixed O&M Cost			
FOMO (\$/kW yr) = (if MW>500 then 16 additional operators, else 12 operators)*2080*T/(A*1000)	\$	3.06	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)	\$	4.81	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$	0.15	Fixed O&M additional administrative labor costs
FOMWW (\$/kW yr) =		0	Fixed O&M costs for wastewater treatment facility
<b>FOM (\$/kW yr) = FOMO +FOMM+FOMA+ FOMWW</b>	<b>\$</b>	<b>8.02</b>	<b>Total Fixed O&amp;M costs</b>
Variable O&M Cost			
VOMR (\$/MWh) = K*P/(A*J)/98	\$	0.17	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = L*Q/(A*J)/98	\$	0.30	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	\$	0.30	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	\$	0.07	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	\$	0.17	Variable O&M costs for wastewater treatment facility
<b>VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW</b>	<b>\$</b>	<b>1.01</b>	<b>Total Variable O&amp;M costs</b>
Annual Capacity Factor =	<b>13.10%</b>		
Annual MWh =	748,172		
Annual Heat Input MMBtu =	6,726,692		
Annual Tons SO2 Created =	2,404	at 100% S conversion	
Annual Tons SO2 Removed =	2,284	at removal efficiency = 95%	
Annual Tons SO2 Emission =	120		
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.036	Value is BELOW a 0.06 floor rate	
Annual Capital Recovery Factor =	<b>0.0944</b>	Wet FGD	7% interest and 20 years useful life
Annual Capital Cost (Including AFUDC), \$ =	38,000,000		
Annual FOM Cost, \$ =	5,200,000		
Annual VOM Cost, \$ =	760,000		
Total Annual FGD Cost, \$ =	<b>44,000,000</b>		
Capital Cost, \$/MWh =	50.79		
FOM Cost, \$/MWh =	6.95		
VOM Cost, \$/MWh =	1.02		
Total FGD Cost, \$/MWh =	<b>58.76</b>		
Capital Cost, \$/ton =	16,638		
FOM Cost, \$/ton =	2,277		
VOM Cost, \$/ton =	333		
Avon Lake Power Plant	Total FGD Cost, \$/ton =	<b>19,200</b>	per ton SO2 removed

Four Factor Analysis

Appendix B

Wet FGD(1.0\_20yr)

Revised March 2021

**Appendix B Table B-4: Wet Flue Gas Desulfurization Cost**

Variable	Designation	Units	Value	Calculation
EPC Project?			<input checked="" type="checkbox"/> TRUE	
Wastewater Treatment		Phys Chem-Biological		
Unit Size	A	(MW)	652	<--- User Input (Greater than 100 MW)
Site elevation	A-1	(ft)	607	
Elevation factor	A-2		1.024	See draft EPA Control Cost Manual
Retrofit Factor	B		1.00	1.0 for an average retrofit. The URS Washington Group Study of 2009 estimated the total capital cost of a wet FGD system at \$389 million. Escalation of the URS capital cost from 2009 estimate to a 2019 cost based on the Chemical Engineering Plant Cost Index (607.5/521.9) indicates a current capital cost of \$453 million.
Heat Rate	C	(Btu/kWh)	8991	<--- User Input, EPA Air Markets Program Data, see Table 4-1
SO2 Rate	D	(lb/MMBtu)	0.71	<--- User Input 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1 of the report.
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.899	C/10000
Heat Input	H	(Btu/hr)	5.86E+09	A*C*1000
Capacity Factor	I	(%)	13.10	<--- User Input 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Operating SO2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Limestone Rate	K	(ton/hr)	4	17.52*A*D*G/2000 (Based on 95% removal)
Design Waste Rate	L	(ton/hr)	7	1.811*K (Based on 95% removal)
Aux Power Include in VOM? <input checked="" type="checkbox"/>	M	(%)	1.18	$(1.12e^{(0.155*D)}) * F * G$
Makeup Water Rate	N	(1000 gph)	47	$(1.674 * D + 74.68) * A * F * G / 1000$
Limestone Cost	P	(\$/ton)	30	<--- User Input
Waste Disposal Cost	Q	(\$/ton)	30	<--- User Input
Aux Power Cost	R	(\$/kWh)	0.025	<--- User Input
Makeup Water Cost	S	(\$/kgal)	1.0	<--- User Input
Operating Labor Rate	T	(\$/hr)	60	<--- User Input (Labor cost including all benefits)

**Appendix B Table B-4: Wet Flue Gas Desulfurization Cost**

<b>Costs are all based on 2016 dollars (except for adjustment of total project cost to 2019)</b>		
<b>Capital Cost Calculation</b>	<b>Cost</b>	<b>Comments</b>
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
$BMF\ 584000*(B)*((F*G)^{0.6})*((D/2)^{0.02})*(A^{0.716})$	\$ 58,565,000	Base absorber island cost x A-2
$BMF\ 202000*(B)*((D*G)^{0.3})*(A^{0.716})$	\$ 18,313,000	Base reagent preparation cost
$BMV\ 106000*(B)*((D*G)^{0.45})*(A^{0.716})$	\$ 8,993,000	Base waste handling cost
$BME\ 1070000*(B)*((F*G)^{0.4})*(A^{0.716})$	\$ 110,801,000	Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, minor WWT, etc... x A-2
BMV If type is Bio-Chem, then $10600000*(B)*A/500^{0.6}$ , else 0	\$ 12,430,037	Base wastewater treatment facility, beyond minor physical/chemical treatment
$BM\ BMR + BMF + BMW + BMB + BMWW$	\$ 209,102,037	Total base module cost including retrofit factor
$BM\ (\$/kW) =$		321 Base cost per kW
<b>Total Project Cost</b>		
A1 = 10% of BM	\$ 20,910,000	Engineering and Construction Management costs
A2= 10% of BM	\$ 20,910,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc....
A3 = 10% of BM	\$ 20,910,000	Contractor profit and fees
<b>CECC (\$) = BM + A1 + A2 + A3</b>	<b>\$ 271,832,037</b>	Capital, engineering and construction cost subtotal
<b>CECC (\$/kW) =</b>	<b>417</b>	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	\$ 13,592,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
$TPC\ (\$) - \text{Includes Owner's Costs} = CECC + B1$	\$ 285,424,037	Total project cost without AFUDC
<b>TPC' (\$/kW) - Includes Owner's Costs</b>	<b>438</b>	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$ 28,542,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC+B1	\$ 45,056,000	EPC fees of 15%
529		
<b>TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1</b>	<b>\$ 403,000,000</b>	Total project cost escalated to 2019, 607.5/541.7 based on Chemical Engineering Plant Cost Index for 2019/2016
<b>TPC (\$/kW) = Includes Owner's Costs and AFUDC</b>	<b>618</b>	Total project cost per kW

**Appendix B Table B-4: Wet Flue Gas Desulfurization Cost**

Fixed O&M Cost			
FOMO (\$/kW yr) = (if MW>500 then 16 additional operators, else 12 operators)*2080*T/(A*1000)	\$	3.06	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)	\$	4.81	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$	0.15	Fixed O&M additional administrative labor costs
FOMWW (\$/kW yr) =		0	Fixed O&M costs for wastewater treatment facility
<b>FOM (\$/kW yr) = FOMO +FOMM+FOMA+ FOMWW</b>	<b>\$</b>	<b>8.02</b>	<b>Total Fixed O&amp;M costs</b>
Variable O&M Cost			
VOMR (\$/MWh) = K*P/(A*J)/98	\$	0.17	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = L*Q/(A*J)/98	\$	0.30	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	\$	0.30	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	\$	0.07	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	\$	0.17	Variable O&M costs for wastewater treatment facility
<b>VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW</b>	<b>\$</b>	<b>1.01</b>	<b>Total Variable O&amp;M costs</b>
Annual Capacity Factor =	<b>13.10%</b>		
Annual MWh =	748,172		
Annual Heat Input MMBtu =	6,726,692		
Annual Tons SO2 Created =	2,404	at 100% S conversion	
Annual Tons SO2 Removed =	2,284	at removal efficiency = 95%	
Annual Tons SO2 Emission =	120		
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.036	Value is BELOW a 0.06 floor rate	
Annual Capital Recovery Factor =	<b>0.0806</b>	Wet FGD	7% interest and 30 years useful life
Annual Capital Cost (Including AFUDC), \$ =	32,500,000		
Annual FOM Cost, \$ =	5,200,000		
Annual VOM Cost, \$ =	760,000		
Total Annual FGD Cost, \$ =	<b>38,500,000</b>		
Capital Cost, \$/MWh =	43.44		
FOM Cost, \$/MWh =	6.95		
VOM Cost, \$/MWh =	1.02		
Total FGD Cost, \$/MWh =	<b>51.41</b>		
Capital Cost, \$/ton =	14,230		
FOM Cost, \$/ton =	2,277		
VOM Cost, \$/ton =	333		
Avon Lake Power Plant	Total FGD Cost, \$/ton =	<b>16,800</b>	per ton SO2 removed

Four Factor Analysis

Appendix B

Wet FGD(1.0\_30yr)

Revised March 2021

**Appendix B Table B-5: Spray Dryer Absorber Cost**

Variable	Designation	Units	Value	Calculation
EPC Project?			<input checked="" type="checkbox"/> TRUE	
Unit Size	A	(MW)	652	<-- User Input (Greater than 50 MW)
Site elevation	A-1	(ft)	607	<-- User Input
Elevation factor	A-2		1.024	See draft EPA Control Cost Manual
Retrofit Factor	B		1.20	<-- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	8991	<-- User Input, EPA Air Markets Program Data, see Table 4-1
SO2 Rate	D	(lb/MMBtu)	0.71	<-- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate) 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Type of Coal	E		1	<-- User Input
Coal Factor	F		1.05	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.899083047	C/10000
Heat Input	H	(Btu/hr)	5.86E+09	A*C*1000
Capacity Factor	I	(%)	13.10	2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Operating SO2 Removal	J	(%)	95	<-- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	3	$(0.6702*(D^2)+13.42*D)*A*G/2000$ (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	7	$(0.8016*(D^2)+31.1917*D)*A*G/2000$ (Based on 95% SO2 removal)
Aux Power Include in VOM? <input checked="" type="checkbox"/>	M	(%)	1.23	$(0.000547*D^2+0.00649*D+1.3)*F*G$
Makeup Water Rate	N	(1000 gph)	34	$(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000$
Lime Cost	P	(\$/ton)	125	<-- User Input
Waste Disposal Cost	Q	(\$/ton)	30	<-- User Input
Aux Power Cost	R	(\$/kWh)	0.06	<-- User Input
Makeup Water Cost	S	(\$/kgal)	1	<-- User Input
Operating Labor Rate	T	(\$/hr)	60	<-- User Input (Labor cost including all benefits)

**Costs are all based on 2016 dollars (except for adjustment of total project cost to 2019)**

Capital Cost Calculation	Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
BMR (\$) = if (A>600 then (A^98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	\$ 76,295,000	Base module absorber island cost x A-2
BMF (\$) = if (A>600 then (A^52000) else 338000*(A^0.716))*B*(G*D)^0.2	\$ 37,242,000	Base module reagent preparation and waste recycle/handling cost
BMB (\$) = if (A>600 then (A^138000) else 899000*(A^0.716))*B*(G*F)^0.4	\$ 110,569,000	Base balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc... x A-2
BM (\$) = BMR + BMF + BMB	\$ 224,106,000	Total base module cost including retrofit factor
BM (\$/kW) =	344	Base cost per kW
<b>Total Project Cost</b>		
A1 = 10% of BM	\$ 22,411,000	Engineering and Construction Management costs
A2 = 10% of BM	\$ 22,411,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM	\$ 22,411,000	Contractor profit and fees
<b>CECC (\$) = BM + A1 + A2 + A3</b>	<b>\$ 291,339,000</b>	Capital, engineering and construction cost subtotal
<b>CECC (\$/kW) =</b>	<b>447</b>	Capital, engineering and construction cost subtotal per kW
B1 = 2% of CECC if EPC TRUE, else 5% of CECC	\$ 5,827,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
<b>TPC' (\$) - Includes Owner's Costs = CECC + B1</b>	<b>\$ 297,166,000</b>	Total project cost without AFUDC
<b>TPC' (\$/kW) - Includes Owner's Costs</b>	<b>456</b>	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$ 29,717,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = if EPC = TRUE, 15% of (CECC+B1), else 0	\$ 44,575,000	EPC fees of 15%
<b>TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1</b>	<b>\$ 417,000,000</b>	Total project cost escalated to 2019, 607.5/541.7 based on Chemical Engineering Plant Cost Index for 2019/2016
<b>TPC (\$/kW) = Includes Owner's Costs and AFUDC</b>	<b>640</b>	Total project cost per kW
<b>Fixed O&amp;M Cost</b>		
FOMO (\$/kW yr) = (8 operators)*2080*T/(A*1000)	\$ 1.53	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) = (BM*0.015)/(B*A*1000)	\$ 4.30	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$ 0.10	Fixed O&M additional administrative labor costs
<b>FOM (\$/kW yr) = FOMO + FOMM + FOMA</b>	<b>\$ 5.93</b>	Total Fixed O&M costs

Variable O&M Cost		
VOMR (\$/MWh) = $K \cdot P / (A \cdot J) / 98$	\$ 0.56	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = $L \cdot Q / (A \cdot J) / 98$	\$ 0.31	Variable O&M costs for waste disposal
VOMP (\$/MWh) = $M \cdot R \cdot 10$	\$ 0.74	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = $N \cdot S / A$	\$ 0.05	Variable O&M costs for makeup water
<b>VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM</b>		
	<b>\$ 1.66</b>	Total Variable O&M costs
Annual Capacity Factor = <b>13%</b>		
Annual MWs = 748,172		
Annual Heat Input MMBtu = 6,726,692		
Annual Tons SO2 Created = 2,404 at 100% S conversion		
Annual Tons SO2 Removed = 2,284 at removal efficiency = 95%		
Annual Tons SO2 Emission = 120		
Annual Avg SO2 Emission Rate, lb/MMBtu = 0.036 <i>Value is BELOW a 0.06 floor rate</i>		
Annual Capital Recovery Factor = <b>0.094</b> 7% interest and 20 years useful life		
Annual Capital Cost (Including AFUDC), \$ = 39,400,000		
Annual FOM Cost, \$ = 3,900,000		
Annual VOM Cost, \$ = 1,200,000		
Total Annual SDA Cost, \$ = <b>44,500,000</b>		
Capital Cost, \$/MWh = 52.66		
FOM Cost, \$/MWh = 5.21		
VOM Cost, \$/MWh = 1.60		
Total SDA Cost, \$/MWh = <b>59.48</b>		
Capital Cost, \$/ton = 17,251		
FOM Cost, \$/ton = 1,708		
VOM Cost, \$/ton = 525		
Total Cost, \$/ton = <b>19,500</b> per ton SO2 removed		

**Appendix B Table B-6: Spray Dryer Absorber Cost**

Variable	Designation	Units	Value	Calculation
EPC Project?			<input checked="" type="checkbox"/> TRUE	
Unit Size	A	(MW)	652	<-- User Input (Greater than 50 MW)
Site elevation	A-1	(ft)	607	<-- User Input
Elevation factor	A-2		1.024	See draft EPA Control Cost Manual
Retrofit Factor	B		1.20	<-- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	8991	<-- User Input, EPA Air Markets Program Data, see Table 4-1
SO2 Rate	D	(lb/MMBtu)	0.71	<-- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate) 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Type of Coal	E		1	<-- User Input
Coal Factor	F		1.05	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.899083047	C/10000
Heat Input	H	(Btu/hr)	5.86E+09	A*C*1000
Capacity Factor	I	(%)	13.10	2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Operating SO2 Removal	J	(%)	95	<-- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	3	$(0.6702*(D^2)+13.42*D)*A*G/2000$ (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	7	$(0.8016*(D^2)+31.1917*D)*A*G/2000$ (Based on 95% SO2 removal)
Aux Power Include in VOM? <input checked="" type="checkbox"/>	M	(%)	1.23	$(0.000547*D^2+0.00649*D+1.3)*F*G$
Makeup Water Rate	N	(1000 gph)	34	$(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000$
Lime Cost	P	(\$/ton)	125	<-- User Input
Waste Disposal Cost	Q	(\$/ton)	30	<-- User Input
Aux Power Cost	R	(\$/kWh)	0.06	<-- User Input
Makeup Water Cost	S	(\$/kgal)	1	<-- User Input
Operating Labor Rate	T	(\$/hr)	60	<-- User Input (Labor cost including all benefits)

**Costs are all based on 2016 dollars (except for adjustment of total project cost to 2019)**

Capital Cost Calculation	Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
BMR (\$) = if (A>600 then (A^98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	\$ 76,295,000	Base module absorber island cost x A-2
BMF (\$) = if (A>600 then (A^52000) else 338000*(A^0.716))*B*(G*D)^0.2	\$ 37,242,000	Base module reagent preparation and waste recycle/handling cost
BMB (\$) = if (A>600 then (A^138000) else 899000*(A^0.716))*B*(G*F)^0.4	\$ 110,569,000	Base balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc... x A-2
BM (\$) = BMR + BMF + BMB	\$ 224,106,000	Total base module cost including retrofit factor
BM (\$/kW) =	344	Base cost per kW
<b>Total Project Cost</b>		
A1 = 10% of BM	\$ 22,411,000	Engineering and Construction Management costs
A2 = 10% of BM	\$ 22,411,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM	\$ 22,411,000	Contractor profit and fees
<b>CECC (\$) = BM + A1 + A2 + A3</b>	<b>\$ 291,339,000</b>	Capital, engineering and construction cost subtotal
<b>CECC (\$/kW) =</b>	<b>447</b>	Capital, engineering and construction cost subtotal per kW
B1 = 2% of CECC if EPC TRUE, else 5% of CECC	\$ 5,827,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
<b>TPC' (\$) - Includes Owner's Costs = CECC + B1</b>	<b>\$ 297,166,000</b>	Total project cost without AFUDC
<b>TPC' (\$/kW) - Includes Owner's Costs</b>	<b>456</b>	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$ 29,717,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = if EPC = TRUE, 15% of (CECC+B1), else 0	\$ 44,575,000	EPC fees of 15%
<b>TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1</b>	<b>\$ 417,000,000</b>	Total project cost escalated to 2019, 607.5/541.7 based on Chemical Engineering Plant Cost Index for 2019/2016
<b>TPC (\$/kW) = Includes Owner's Costs and AFUDC</b>	<b>640</b>	Total project cost per kW
<b>Fixed O&amp;M Cost</b>		
FOMO (\$/kW yr) = (8 operators)*2080*T/(A*1000)	\$ 1.53	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)	\$ 4.30	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$ 0.10	Fixed O&M additional administrative labor costs
<b>FOM (\$/kW yr) = FOMO +FOMM+FOMA</b>	<b>\$ 5.93</b>	Total Fixed O&M costs

Variable O&M Cost		
VOMR (\$/MWh) = $K \cdot P / (A \cdot J) / 98$	\$ 0.56	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = $L \cdot Q / (A \cdot J) / 98$	\$ 0.31	Variable O&M costs for waste disposal
VOMP (\$/MWh) = $M \cdot R \cdot 10$	\$ 0.74	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = $N \cdot S / A$	\$ 0.05	Variable O&M costs for makeup water
<b>VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM</b>		
	<b>\$ 1.66</b>	Total Variable O&M costs
Annual Capacity Factor = <b>13%</b>		
Annual MWs = 748,172		
Annual Heat Input MMBtu = 6,726,692		
Annual Tons SO2 Created = 2,404 at 100% S conversion		
Annual Tons SO2 Removed = 2,284 at removal efficiency = 95%		
Annual Tons SO2 Emission = 120		
Annual Avg SO2 Emission Rate, lb/MMBtu = 0.036 <i>Value is BELOW a 0.06 floor rate</i>		
Annual Capital Recovery Factor = <b>0.081</b> 7% interest and 30 years useful life		
Annual Capital Cost (Including AFUDC), \$ = 33,600,000		
Annual FOM Cost, \$ = 3,900,000		
Annual VOM Cost, \$ = 1,200,000		
Total Annual SDA Cost, \$ = <b>38,700,000</b>		
Capital Cost, \$/MWh = 44.91		
FOM Cost, \$/MWh = 5.21		
VOM Cost, \$/MWh = 1.60		
Total SDA Cost, \$/MWh = <b>51.73</b>		
Capital Cost, \$/ton = 14,711		
FOM Cost, \$/ton = 1,708		
VOM Cost, \$/ton = 525		
Total Cost, \$/ton = <b>16,900</b> per ton SO2 removed		

**Appendix B Table B-7: Spray Dryer Absorber Cost**

Variable	Designation	Units	Value	Calculation
EPC Project?			<input checked="" type="checkbox"/> TRUE	
Unit Size	A	(MW)	652	<-- User Input (Greater than 50 MW)
Site elevation	A-1	(ft)	607	<-- User Input
Elevation factor	A-2		1.024	See draft EPA Control Cost Manual
Retrofit Factor	B		1.00	<-- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	8991	<-- User Input, EPA Air Markets Program Data, see Table 4-1
SO2 Rate	D	(lb/MMBtu)	0.71	<-- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate) 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Type of Coal	E		1	<-- User Input
Coal Factor	F		1.05	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.899083047	C/10000
Heat Input	H	(Btu/hr)	5.86E+09	A*C*1000
Capacity Factor	I	(%)	13.10	2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Operating SO2 Removal	J	(%)	95	<-- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	3	$(0.6702*(D^2)+13.42*D)*A*G/2000$ (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	7	$(0.8016*(D^2)+31.1917*D)*A*G/2000$ (Based on 95% SO2 removal)
Aux Power Include in VOM? <input checked="" type="checkbox"/>	M	(%)	1.23	$(0.000547*D^2+0.00649*D+1.3)*F*G$
Makeup Water Rate	N	(1000 gph)	34	$(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000$
Lime Cost	P	(\$/ton)	125	<-- User Input
Waste Disposal Cost	Q	(\$/ton)	30	<-- User Input
Aux Power Cost	R	(\$/kWh)	0.06	<-- User Input
Makeup Water Cost	S	(\$/kgal)	1	<-- User Input
Operating Labor Rate	T	(\$/hr)	60	<-- User Input (Labor cost including all benefits)

**Costs are all based on 2016 dollars (except for adjustment of total project cost to 2019)**

Capital Cost Calculation	Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
BMR (\$) = if (A>600 then (A*98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	\$ 63,580,000	Base module absorber island cost x A-2
BMF (\$) = if (A>600 then (A*52000) else 338000*(A^0.716))*B*(G*D)^0.2	\$ 31,035,000	Base module reagent preparation and waste recycle/handling cost
BMB (\$) = if (A>600 then (A*138000) else 899000*(A^0.716))*B*(G*F)^0.4	\$ 92,141,000	Base balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc... x A-2
BM (\$) = BMR + BMF + BMB	\$ 186,756,000	Total base module cost including retrofit factor
BM (\$/kW) =	286	Base cost per kW
<b>Total Project Cost</b>		
A1 = 10% of BM	\$ 18,676,000	Engineering and Construction Management costs
A2 = 10% of BM	\$ 18,676,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM	\$ 18,676,000	Contractor profit and fees
<b>CECC (\$) = BM + A1 + A2 + A3</b>	<b>\$ 242,784,000</b>	Capital, engineering and construction cost subtotal
<b>CECC (\$/kW) =</b>	<b>372</b>	Capital, engineering and construction cost subtotal per kW
B1 = 2% of CECC if EPC TRUE, else 5% of CECC	\$ 4,856,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
<b>TPC' (\$) - Includes Owner's Costs = CECC + B1</b>	<b>\$ 247,640,000</b>	Total project cost without AFUDC
<b>TPC' (\$/kW) - Includes Owner's Costs</b>	<b>380</b>	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$ 24,764,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = if EPC = TRUE, 15% of (CECC+B1), else 0	\$ 37,146,000	EPC fees of 15%
<b>TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1</b>	<b>\$ 347,000,000</b>	Total project cost escalated to 2019, 607.5/541.7 based on Chemical Engineering Plant Cost Index for 2019/2016
<b>TPC (\$/kW) = Includes Owner's Costs and AFUDC</b>	<b>532</b>	Total project cost per kW
<b>Fixed O&amp;M Cost</b>		
FOMO (\$/kW yr) = (8 operators)*2080*T/(A*1000)	\$ 1.53	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) = (BM*0.015)/(B*A*1000)	\$ 4.30	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$ 0.10	Fixed O&M additional administrative labor costs
<b>FOM (\$/kW yr) = FOMO + FOMM + FOMA</b>	<b>\$ 5.93</b>	Total Fixed O&M costs

Variable O&M Cost		
VOMR (\$/MWh) = $K \cdot P / (A \cdot J) / 98$	\$ 0.56	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = $L \cdot Q / (A \cdot J) / 98$	\$ 0.31	Variable O&M costs for waste disposal
VOMP (\$/MWh) = $M \cdot R \cdot 10$	\$ 0.74	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = $N \cdot S / A$	\$ 0.05	Variable O&M costs for makeup water
<b>VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM</b>		
	<b>\$ 1.66</b>	<b>Total Variable O&amp;M costs</b>
Annual Capacity Factor = <b>13%</b>		
Annual MWhs = 748,172		
Annual Heat Input MMBtu = 6,726,692		
Annual Tons SO2 Created = 2,404 at 100% S conversion		
Annual Tons SO2 Removed = 2,284 at removal efficiency = 95%		
Annual Tons SO2 Emission = 120		
Annual Avg SO2 Emission Rate, lb/MMBtu = 0.036 Value is BELOW a 0.06 floor rate		
Annual Capital Recovery Factor = <b>0.094</b> 7% interest and 20 years useful life		
Annual Capital Cost (Including AFUDC), \$ = 32,800,000		
Annual FOM Cost, \$ = 3,900,000		
Annual VOM Cost, \$ = 1,200,000		
Total Annual SDA Cost, \$ = <b>37,900,000</b>		
Capital Cost, \$/MWh = 43.84		
FOM Cost, \$/MWh = 5.21		
VOM Cost, \$/MWh = 1.60		
Total SDA Cost, \$/MWh = <b>50.66</b>		
Capital Cost, \$/ton = 14,361		
FOM Cost, \$/ton = 1,708		
VOM Cost, \$/ton = 525		
Total Cost, \$/ton = <b>16,600 per ton SO2 removed</b>		

Appendix B Table B-8: Spray Dryer Absorber Cost

Variable	Designation	Units	Value	Calculation
EPC Project?			<input checked="" type="checkbox"/> TRUE	
Unit Size	A	(MW)	652	<-- User Input (Greater than 50 MW)
Site elevation	A-1	(ft)	607	<-- User Input
Elevation factor	A-2		1.024	See draft EPA Control Cost Manual
Retrofit Factor	B		1.00	<-- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	8991	<-- User Input, EPA Air Markets Program Data, see Table 4-1
SO2 Rate	D	(lb/MMBtu)	0.71	<-- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate) 2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Type of Coal	E		1	<-- User Input
Coal Factor	F		1.05	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.899083047	C/10000
Heat Input	H	(Btu/hr)	5.86E+09	A*C*1000
Capacity Factor	I	(%)	13.10	2017 through 2019 average, EPA Air Markets Program Data, see Table 4-1
Operating SO2 Removal	J	(%)	95	<-- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	3	$(0.6702*(D^2)+13.42*D)*A*G/2000$ (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	7	$(0.8016*(D^2)+31.1917*D)*A*G/2000$ (Based on 95% SO2 removal)
Aux Power Include in VOM? <input checked="" type="checkbox"/>	M	(%)	1.23	$(0.000547*D^2+0.00649*D+1.3)*F*G$
Makeup Water Rate	N	(1000 gph)	34	$(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000$
Lime Cost	P	(\$/ton)	125	<-- User Input
Waste Disposal Cost	Q	(\$/ton)	30	<-- User Input
Aux Power Cost	R	(\$/kWh)	0.06	<-- User Input
Makeup Water Cost	S	(\$/kgal)	1	<-- User Input
Operating Labor Rate	T	(\$/hr)	60	<-- User Input (Labor cost including all benefits)

**Costs are all based on 2016 dollars (except for adjustment of total project cost to 2019)**

Capital Cost Calculation	Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
BMR (\$) = if (A>600 then (A^98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	\$ 63,580,000	Base module absorber island cost x A-2
BMF (\$) = if (A>600 then (A^52000) else 338000*(A^0.716))*B*(G*D)^0.2	\$ 31,035,000	Base module reagent preparation and waste recycle/handling cost
BMB (\$) = if (A>600 then (A^138000) else 899000*(A^0.716))*B*(G*F)^0.4	\$ 92,141,000	Base balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc... x A-2
BM (\$) = BMR + BMF + BMB	\$ 186,756,000	Total base module cost including retrofit factor
BM (\$/kW) =	286	Base cost per kW
<b>Total Project Cost</b>		
A1 = 10% of BM	\$ 18,676,000	Engineering and Construction Management costs
A2 = 10% of BM	\$ 18,676,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM	\$ 18,676,000	Contractor profit and fees
<b>CECC (\$) = BM + A1 + A2 + A3</b>	<b>\$ 242,784,000</b>	Capital, engineering and construction cost subtotal
<b>CECC (\$/kW) =</b>	<b>372</b>	Capital, engineering and construction cost subtotal per kW
B1 = 2% of CECC if EPC TRUE, else 5% of CECC	\$ 4,856,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
<b>TPC' (\$) - Includes Owner's Costs = CECC + B1</b>	<b>\$ 247,640,000</b>	Total project cost without AFUDC
<b>TPC' (\$/kW) - Includes Owner's Costs</b>	<b>380</b>	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$ 24,764,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = if EPC = TRUE, 15% of (CECC+B1), else 0	\$ 37,146,000	EPC fees of 15%
<b>TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1</b>	<b>\$ 347,000,000</b>	Total project cost escalated to 2019, 607.5/541.7 based on Chemical Engineering Plant Cost Index for 2019/2016
<b>TPC (\$/kW) = Includes Owner's Costs and AFUDC</b>	<b>532</b>	Total project cost per kW
<b>Fixed O&amp;M Cost</b>		
FOMO (\$/kW yr) = (8 operators)*2080*T/(A*1000)	\$ 1.53	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)	\$ 4.30	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$ 0.10	Fixed O&M additional administrative labor costs
<b>FOM (\$/kW yr) = FOMO +FOMM+FOMA</b>	<b>\$ 5.93</b>	Total Fixed O&M costs

Variable O&M Cost		
VOMR (\$/MWh) = $K \cdot P / (A \cdot J) / 98$	\$ 0.56	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = $L \cdot Q / (A \cdot J) / 98$	\$ 0.31	Variable O&M costs for waste disposal
VOMP (\$/MWh) = $M \cdot R \cdot 10$	\$ 0.74	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = $N \cdot S / A$	\$ 0.05	Variable O&M costs for makeup water
<b>VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM</b>		
	<b>\$ 1.66</b>	<b>Total Variable O&amp;M costs</b>
Annual Capacity Factor = <b>13%</b>		
Annual MWs = 748,172		
Annual Heat Input MMBtu = 6,726,692		
Annual Tons SO2 Created = 2,404 at 100% S conversion		
Annual Tons SO2 Removed = 2,284 at removal efficiency = 95%		
Annual Tons SO2 Emission = 120		
Annual Avg SO2 Emission Rate, lb/MMBtu = 0.036 <i>Value is BELOW a 0.06 floor rate</i>		
Annual Capital Recovery Factor = <b>0.081</b> 7% interest and 30 years useful life		
Annual Capital Cost (Including AFUDC), \$ = 28,000,000		
Annual FOM Cost, \$ = 3,900,000		
Annual VOM Cost, \$ = 1,200,000		
Total Annual SDA Cost, \$ = <b>33,100,000</b>		
Capital Cost, \$/MWh = 37.42		
FOM Cost, \$/MWh = 5.21		
VOM Cost, \$/MWh = 1.60		
Total SDA Cost, \$/MWh = <b>44.24</b>		
Capital Cost, \$/ton = 12,260		
FOM Cost, \$/ton = 1,708		
VOM Cost, \$/ton = 525		
Total Cost, \$/ton = <b>14,500</b> per ton SO2 removed		

## Data Inputs - SNCR Cost Evaluation

Avon Lake Power Plant Unit 9/Boiler 12

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (GMw)? 652 MW (gross)

What is the higher heating value (HHV) of the fuel? 11,234 Btu/lb

What is the estimated actual annual MWh output? 563,823 MWhs (2017 - 2019 actual Gross MW) x 0.7536 (fraction of annual time when unit at a load > 300 MW)

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.89 MMBtu/MW (2017 - 2019 actual Gross MWh divided by 2017 - 2019 MMBtu) x 0.9891 (to account for the lower heat rate at higher loads)

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

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

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.414 percent by weight  
or  
Select the appropriate SO<sub>2</sub> emission rate: Not Applicable

Ash content (%Ash): 9.23 percent by weight  
\*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

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

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

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

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates ( $t_{SNCR}$ )	365	calculate the correct capacity factor ( $CF_{total}$ )
Inlet $NO_x$ Emissions ( $NO_{x_{in}}$ ) to SNCR	0.327	lb/MMBtu (based on actual operation in 2017 - 2019) at >300 MW
Outlet $NO_x$ Emissions ( $NO_{x_{out}}$ ) from SNCR	0.262	lb/MMBtu (based on 20% control)
Estimated Normalized Stoichiometric Ratio (NSR)	1.00	Based on 2005 demonstration
Concentration of reagent as stored ( $C_{stored}$ )	50	Percent
Density of reagent as stored ( $\rho_{stored}$ )	71	lb/ft <sup>3</sup>
Concentration of reagent injected ( $C_{inj}$ )	50	percent
Number of days reagent is stored ( $t_{storage}$ )	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation

607 Feet above sea level

\*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous $NH_3$	56 lbs/ft <sup>3</sup>

Enter the cost data for the proposed SNCR:

Desired dollar-year CEPCI for 2019	2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7	Percent			
Fuel ( $Cost_{fuel}$ )	2.40	\$/MMBtu*			
Reagent ( $Cost_{reag}$ )	1.08	\$/gallon for a 50 percent solution of urea			
Water ( $Cost_{water}$ )	0.0042	\$/gallon*			
Electricity ( $Cost_{elect}$ )	0.0250	\$/kWh			
Ash Disposal (for coal-fired boilers only) ( $Cost_{ash}$ )	48.80	\$/ton*			

CEPCI = Chemical Engineering Plant Cost Index

Quote from Bill Leighton (Colonial Chemical Co.) Email dated 08/05/2020.

Estimate from the Plant

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

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

Maintenance and Administrative Charges Cost Factors:

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

## SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	5,798	MMBtu/hour
Maximum Annual MWh Output =	$Bmw \times 8760 =$	5,711,520	MWhs (2017 - 2019 actual Gross MW) x 0.7536 (fraction of annual time when unit at a load > 300 MW)
Estimated Actual Annual MWh Output (Boutput) =		563,823	MWhs (2017 - 2019 actual Gross MW) x 0.7536 (fraction of annual time when unit at a load > 300 MW)
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.89	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (tsnrcr/365) =$	0.099	fraction
Total operating time for the SNCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	865	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	20	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	379.20	lb/hour
Total NO <sub>x</sub> removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	163.96	tons/year
Coal Factor ( $Coal_F$ ) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	$14.7 \text{ psia}/P =$	1.02	
Atmospheric pressure at 607 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^*$ =	14.4	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

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

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_B \times \text{NSR} \times \text{MW}_R) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH <sub>3</sub> ; 2 for Urea)	1237	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / C_{\text{sol}} =$	2,475	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	260.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	87,700	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

7% and 20 year life

7% and 30 year life

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

Parameter	Equation	Calculated Value	Units
<b>Electricity Usage:</b>			
Electricity Consumption (P) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_B) / \text{NPHR} =$	100.2	kW/hour
<b>Water Usage:</b>			
Water consumption ( $q_w$ ) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	0	gallons/hour
<b>Fuel Data:</b>			
Additional Fuel required to evaporate water in injected reagent ( $\Delta\text{Fuel}$ ) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	1.11	MMBtu/hour
<b>Ash Disposal:</b>			
Additional ash produced due to increased fuel consumption ( $\Delta\text{ash}$ ) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	9.2	lb/hour

# Cost Estimate

## Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$3,830,308 in 2019 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$0 in 2019 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$6,210,163 in 2019 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$13,000,000 in 2019 dollars</b>

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

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$3,830,308 in 2019 dollars
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### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$0 in 2019 dollars
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\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/\text{NPHR})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$6,210,163 in 2019 dollars
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## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$443,205 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$1,233,050 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$1,676,255 in 2019 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$195,000 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$243,534 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$2,166 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$0 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$2,311 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$193 in 2019 dollars
Direct Annual Cost =		\$443,205 in 2019 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$5,850 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$1,227,200 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$1,233,050 in 2019 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$1,676,000 per year in 2019 dollars
NOx Removed =	164 tons/year
Cost Effectiveness =	\$10,200 per ton of NOx removed in 2019 dollars

## Data Inputs - SNCR Cost Evaluation

Avon Lake Power Plant Unit 9/Boiler 12

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Utility

What type of fuel does the unit burn?

Coal

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

Retrofit

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

1

Complete all of the highlighted data fields:

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

652 MW (gross)

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

11,234 Btu/lb

What is the estimated actual annual MWh output?

563,823 MWhs (2017 - 2019 actual Gross MW) x 0.7536 (fraction of annual time when unit at a load > 300 MW)

Is the boiler a fluid-bed boiler?

No

Enter the net plant heat input rate (NPHR)

8.89 MMBtu/MW (2017 - 2019 actual Gross MWh divided by 2017 - 2019 MMBtu) x 0.9891 (to account for the lower heat rate at higher loads)

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

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

Provide the following information for coal-fired boilers:

Type of coal burned:

Sub-Bituminous

Enter the sulfur content (%S) = 0.414 percent by weight

or

Select the appropriate SO<sub>2</sub> emission rate:

Not Applicable

Ash content (%Ash): 9.23 percent by weight

\*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

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

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

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

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates ( $t_{SNCR}$ )	365	calculate the correct capacity factor ( $CF_{total}$ )
Inlet $NO_x$ Emissions ( $NO_{x,in}$ ) to SNCR	0.327	lb/MMBtu (based on actual operation in 2017 - 2019) at >300 MW
Outlet $NO_x$ Emissions ( $NO_{x,out}$ ) from SNCR	0.262	lb/MMBtu (based on 20% control)
Estimated Normalized Stoichiometric Ratio (NSR)	1.00	Based on 2005 demonstration
Concentration of reagent as stored ( $C_{stored}$ )	50 Percent	
Density of reagent as stored ( $\rho_{stored}$ )	71 lb/ft <sup>3</sup>	
Concentration of reagent injected ( $C_{in}$ )	50 percent	
Number of days reagent is stored ( $t_{storage}$ )	14 days	
Estimated equipment life	30 Years	
Select the reagent used	Urea	

Plant Elevation

607 Feet above sea level
--------------------------

\*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous $NH_3$	56 lbs/ft <sup>3</sup>

Enter the cost data for the proposed SNCR:

Desired dollar-year CEPCI for 2019	2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7 Percent				
Fuel ( $Cost_{fuel}$ )	2.40 \$/MMBtu*				
Reagent ( $Cost_{reag}$ )	1.08 \$/gallon for a 50 percent solution of urea				
Water ( $Cost_{water}$ )	0.0042 \$/gallon*				
Electricity ( $Cost_{elect}$ )	0.0250 \$/kWh				
Ash Disposal (for coal-fired boilers only) ( $Cost_{ash}$ )	48.80 \$/ton*				

CEPCI = Chemical Engineering Plant Cost Index

Quote from Bill Leighton (Colonial Chemical Co.) Email dated 08/05/2020.

Estimate from the Plant

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

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

Maintenance and Administrative Charges Cost Factors:

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

## SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	5,798	MMBtu/hour
Maximum Annual MWh Output =	$Bmw \times 8760 =$	5,711,520	MWhs (2017 - 2019 actual Gross MW) x 0.7536 (fraction of annual time when unit at a load > 300 MW)
Estimated Actual Annual MWh Output (Boutput) =		563,823	MWhs (2017 - 2019 actual Gross MW) x 0.7536 (fraction of annual time when unit at a load > 300 MW)
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.89	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (tsnrcr/365) =$	0.099	fraction
Total operating time for the SNCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	865	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	20	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	379.20	lb/hour
Total NO <sub>x</sub> removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	163.96	tons/year
Coal Factor ( $Coal_F$ ) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	$14.7 \text{ psia}/P =$	1.02	
Atmospheric pressure at 607 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^*$ =	14.4	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

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

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_B \times \text{NSR} \times \text{MW}_R) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH <sub>3</sub> ; 2 for Urea)	1237	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / C_{\text{sol}} =$	2,475	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	260.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	87,700	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

7% and 30 year life

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

Parameter	Equation	Calculated Value	Units
<b>Electricity Usage:</b>			
Electricity Consumption (P) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_B) / \text{NPHR} =$	100.2	kW/hour
<b>Water Usage:</b>			
Water consumption ( $q_w$ ) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	0	gallons/hour
<b>Fuel Data:</b>			
Additional Fuel required to evaporate water in injected reagent ( $\Delta\text{Fuel}$ ) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	1.11	MMBtu/hour
<b>Ash Disposal:</b>			
Additional ash produced due to increased fuel consumption ( $\Delta\text{ash}$ ) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	9.2	lb/hour

# Cost Estimate

## Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR (SNCR <sub>cost</sub> ) =	\$3,830,308 in 2019 dollars
Air Pre-Heater Costs (APH <sub>cost</sub> ) <sup>*</sup> =	\$0 in 2019 dollars
Balance of Plant Costs (BOP <sub>cost</sub> ) =	\$6,210,163 in 2019 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$13,000,000 in 2019 dollars</b>

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

### SNCR Capital Costs (SNCR<sub>cost</sub>)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs (SNCR <sub>cost</sub> ) =	\$3,830,308 in 2019 dollars
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### Air Pre-Heater Costs (APH<sub>cost</sub>)<sup>\*</sup>

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH <sub>cost</sub> ) =	\$0 in 2019 dollars
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<sup>\*</sup> Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs (BOP<sub>cost</sub>)

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/\text{NPHR})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

Balance of Plant Costs (BOP <sub>cost</sub> ) =	\$6,210,163 in 2019 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$443,205 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$1,053,650 in 2019 dollars
<b>Total annual costs (TAC) = DAC + IDAC</b>	<b>\$1,496,855 in 2019 dollars</b>

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$195,000 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$243,534 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$2,166 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$0 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$2,311 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$193 in 2019 dollars
<b>Direct Annual Cost =</b>		<b>\$443,205 in 2019 dollars</b>

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$5,850 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$1,047,800 in 2019 dollars
<b>Indirect Annual Cost (IDAC) =</b>	<b>AC + CR =</b>	<b>\$1,053,650 in 2019 dollars</b>

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$1,497,000 per year in 2019 dollars
NOx Removed =	164 tons/year
<b>Cost Effectiveness =</b>	<b>\$9,100 per ton of NOx removed in 2019 dollars</b>

## Data Inputs

Avon Lake Power Plant Unit 9/Boiler 12

### EPA Air Pollution Control Cost Manual

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Coal

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

1.2

\* NOTE: You must document why a retrofit factor of 1.2 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 652 MW (gross)

What is the higher heating value (HHV) of the fuel? 11,234 Btu/lb

What is the estimated actual annual MWhs output? 748,172 MWh (2017 - 2019 actual Gross MW)

Enter the net plant heat input rate (NPHR) MMBtu/MW (2017 - 2019 actual Gross MWh divided by 2017 - 2019 MMBtu)  
9.0

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

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

Plant Elevation 607 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.414 percent by weight

For units burning coal blends:

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

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

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

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

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{SCR}$ )

days (based on actual 75 operation in 2017 - 2019)
---

Number of days the boiler operates ( $t_{plant}$ )

days (based on actual 75 operation in 2017 - 2019)
---

Inlet NO<sub>x</sub> Emissions (NO<sub>x,in</sub>) to SCR

0.317 lb/MMBtu (based on actual operation in 2017 - 2019)
--

Outlet NO<sub>x</sub> Emissions (NO<sub>x,out</sub>) from SCR

0.031679 lb/MMBtu (90% control)
---------------------------------

Stoichiometric Ratio Factor (SRF)

1.050
-------

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

Number of SCR reactor chambers ( $n_{SCR}$ )

1
---

Number of catalyst layers ( $R_{layer}$ )

3
---

Number of empty catalyst layers ( $R_{empty}$ )

1
---

Ammonia Slip (Slip) provided by vendor

2 ppm
-------

Volume of the catalyst layers ( $Vol_{catalyst}$ )  
(Enter "UNK" if value is not known)

UNK Cubic feet
----------------

Flue gas flow rate ( $Q_{fluegas}$ )

(Enter "UNK" if value is not known)

UNK acfm
----------

Estimated operating life of the catalyst ( $H_{catalyst}$ )

24,000 hours
--------------

Estimated SCR equipment life

20 Years*
-----------

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

Gas temperature at the SCR inlet (T)

650 °F
--------

Base case fuel gas volumetric flow rate factor ( $Q_{fuel}$ )

516 ft <sup>3</sup> /min-MMBtu/hour
-------------------------------------

Concentration of reagent as stored ( $C_{stored}$ )

29 percent*
-------------

Density of reagent as stored ( $\rho_{stored}$ )

56 lb/cubic feet*
-------------------

Number of days reagent is stored ( $t_{storage}$ )

14 days
---------

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

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

Select the reagent used

Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7.00	Percent		
Reagent (Cost <sub>reag</sub> )	0.293	\$/gallon for 29% ammonia*		
Electricity (Cost <sub>elect</sub> )	0.0250	\$/kWh		
Catalyst cost (CC <sub>replace</sub> )	227.00	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)		
Operator Labor Rate	60.00	\$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

\* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

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

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

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

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

Maintenance and Administrative Charges Cost Factors:

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

## SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	5,862	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	5,711,520	MWh (2017 - 2019 actual Gross MW)
Estimated Actual Annual MWhs Output (Boutput) =		748,172	MWh (2017 - 2019 actual Gross MW)
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.90	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (tscr/tplant) =$	0.131	fraction
Total operating time for the SCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	1148	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	1671.30	lb/hour
Total NOx removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	958.91	tons/year
NOx removal factor (NRF) =	$EF/80 =$	1.13	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	2,894,424	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	112.83	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVf) =	$14.7\ psia/P =$	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	14.39	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.20	

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / ((1 + \text{interest rate})^Y - 1)$ , where $Y = H_{\text{catalysts}} / (t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.0497	Fraction
Catalyst volume ( $Vol_{\text{catalyst}}$ ) =	$2.81 \times Q_B \times EF_{\text{adj}} \times Slip_{\text{adj}} \times NO_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}} / N_{\text{scr}})$	25,652.22	Cubic feet
Cross sectional area of the catalyst ( $A_{\text{catalyst}}$ ) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	3,015	ft <sup>2</sup>
Height of each catalyst layer ( $H_{\text{layer}}$ ) =	$(Vol_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{\text{SCR}}$ ) =	$1.15 \times A_{\text{catalyst}}$	3,467	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	58.9	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + H_{\text{layer}}) + 9\text{ft}$	52	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft<sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	650	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / \text{Csol} =$	2,240	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	299	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	100,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	3561.89	kW

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

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

Capital costs for the SCR ( $SCR_{cost}$ ) =	\$160,661,630	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$4,853,015	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$10,793,376	in 2019 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$229,000,000</b>	<b>in 2019 dollars</b>

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

#### SCR Capital Costs ( $SCR_{cost}$ )

For Coal-Fired Utility Boilers >25 MW:

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

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

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

SCR Capital Costs ( $SCR_{cost}$ ) = \$160,661,630 in 2019 dollars

#### Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

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

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

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

Reagent Preparation Costs (RPC) = \$4,853,015 in 2019 dollars

#### Air Pre-Heater Costs (APHC)\*

For Coal-Fired Utility Boilers >25MW:

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

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

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

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

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

#### Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

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

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

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

Balance of Plant Costs ( $BOP_{cost}$ ) = \$10,793,376 in 2019 dollars

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,965,208 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$21,631,880 in 2019 dollars
<b>Total annual costs (TAC) = DAC + IDAC</b>	<b>\$25,597,088 in 2019 dollars</b>

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	0.005 x TCI =	\$1,145,000 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$100,594 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$102,182 in 2019 dollars
Annual Catalyst Replacement Cost =		\$2,617,432 in 2019 dollars
For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/R_{\text{layer}}) \times \text{FWF}$	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	$B_{\text{MW}} \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$	
Direct Annual Cost =		\$3,965,208 in 2019 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$14,280 in 2019 dollars
Capital Recovery Costs (CR) =	CRF x TCI =	\$21,617,600 in 2019 dollars
<b>Indirect Annual Cost (IDAC) =</b>	<b>AC + CR =</b>	<b>\$21,631,880 in 2019 dollars</b>

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$25,597,088 per year in 2019 dollars
NOx Removed =	959 tons/year
<b>Cost Effectiveness =</b>	<b>\$26,700 per ton of NOx removed in 2019 dollars</b>

## Data Inputs

Avon Lake Power Plant Unit 9/Boiler 12

### EPA Air Pollution Control Cost Manual

Is the combustion unit a utility or industrial boiler? Utility ▼

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

What type of fuel does the unit burn? Coal ▼

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

1.2

\* NOTE: You must document why a retrofit factor of 1.2 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 652 MW (gross)

What is the higher heating value (HHV) of the fuel? 11,234 Btu/lb

What is the estimated actual annual MWhs output? 748,172 MWh (2017 - 2019 actual Gross MW)

Enter the net plant heat input rate (NPHR) 9.0 MMBtu/MW (2017 - 2019 actual Gross MWh divided by 2017 - 2019 MMBtu)

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

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

Plant Elevation 607 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous ▼

Enter the sulfur content (%S) = 0.414 percent by weight

For units burning coal blends:

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

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

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

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

- Method 1  
 Method 2  
 Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{SCR}$ )	75 days (based on actual operation in 2017 - 2019)
Number of days the boiler operates ( $t_{plant}$ )	75 days (based on actual operation in 2017 - 2019)
Inlet NO <sub>x</sub> Emissions (NO <sub>x,in</sub> ) to SCR	0.317 lb/MMBtu (based on actual operation in 2017 - 2019)
Outlet NO <sub>x</sub> Emissions (NO <sub>x,out</sub> ) from SCR	0.031679 lb/MMBtu (90% control)
Stoichiometric Ratio Factor (SRF)	1.050

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

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

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

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

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

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

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

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

Select the reagent used

Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5 <i>Enter the CEPCI value for 2019</i>	541.7	2016 CEPCI
Annual Interest Rate (i)	7.00	Percent	
Reagent (Cost <sub>reag</sub> )	0.293 \$/gallon for 29% ammonia*		
Electricity (Cost <sub>elect</sub> )	0.0250 \$/kWh		
Catalyst cost (CC <sub>replace</sub> )	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)		
Operator Labor Rate	60.00 \$/hour (including benefits)*		
Operator Hours/Day	4.00 hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

\* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

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

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

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

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

Maintenance and Administrative Charges Cost Factors:

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

## SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	5,862	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	5,711,520	MWh (2017 - 2019 actual Gross MW)
Estimated Actual Annual MWhs Output (Boutput) =		748,172	MWh (2017 - 2019 actual Gross MW)
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.90	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (tscr/tplant) =$	0.131	fraction
Total operating time for the SCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	1148	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	1671.30	lb/hour
Total NOx removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	958.91	tons/year
NOx removal factor (NRF) =	$EF/80 =$	1.13	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	2,894,424	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	112.83	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVf) =	$14.7\ psia/P =$	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.39	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.20	

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / ((1 + \text{interest rate})^Y - 1)$ , where $Y = H_{\text{catalysts}} / (t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.0497	Fraction
Catalyst volume ( $Vol_{\text{catalyst}}$ ) =	$2.81 \times Q_B \times EF_{\text{adj}} \times Slip_{\text{adj}} \times NO_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}} / N_{\text{scr}})$	25,652.22	Cubic feet
Cross sectional area of the catalyst ( $A_{\text{catalyst}}$ ) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	3,015	ft <sup>2</sup>
Height of each catalyst layer ( $H_{\text{layer}}$ ) =	$(Vol_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{\text{SCR}}$ ) =	$1.15 \times A_{\text{catalyst}}$	3,467	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	58.9	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + H_{\text{layer}}) + 9\text{ft}$	52	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft<sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	650	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / \text{Csol} =$	2,240	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	299	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	100,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	3561.89	kW

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

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

Capital costs for the SCR ( $SCR_{cost}$ ) =	\$160,661,630	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$4,853,015	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$10,793,376	in 2019 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$229,000,000</b>	<b>in 2019 dollars</b>

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

#### SCR Capital Costs ( $SCR_{cost}$ )

For Coal-Fired Utility Boilers >25 MW:

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

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

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

SCR Capital Costs ( $SCR_{cost}$ ) = \$160,661,630 in 2019 dollars

#### Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

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

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

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

Reagent Preparation Costs (RPC) = \$4,853,015 in 2019 dollars

#### Air Pre-Heater Costs (APHC)\*

For Coal-Fired Utility Boilers >25MW:

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

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

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

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

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

#### Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

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

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

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

Balance of Plant Costs ( $BOP_{cost}$ ) = \$10,793,376 in 2019 dollars

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,965,208 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$18,471,680 in 2019 dollars
<b>Total annual costs (TAC) = DAC + IDAC</b>	<b>\$22,436,888 in 2019 dollars</b>

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	$0.005 \times \text{TCl} =$	\$1,145,000 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$100,594 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$102,182 in 2019 dollars
Annual Catalyst Replacement Cost =		\$2,617,432 in 2019 dollars
For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/\text{R}_{\text{layer}}) \times \text{FWF}$	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	$B_{\text{MW}} \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$	
Direct Annual Cost =		\$3,965,208 in 2019 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$14,280 in 2019 dollars
Capital Recovery Costs (CR) =	$\text{CRF} \times \text{TCl} =$	\$18,457,400 in 2019 dollars
<b>Indirect Annual Cost (IDAC) =</b>	<b>AC + CR =</b>	<b>\$18,471,680 in 2019 dollars</b>

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$22,436,888 per year in 2019 dollars
NOx Removed =	959 tons/year
<b>Cost Effectiveness =</b>	<b>\$23,400 per ton of NOx removed in 2019 dollars</b>

## Data Inputs

Avon Lake Power Plant Unit 9/Boiler 12

### EPA Air Pollution Control Cost Manual

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Coal ▼

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

Retrofit ▼

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

1

Complete all of the highlighted data fields:

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

652 MW (gross)

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

11,234 Btu/lb

What is the estimated actual annual MWhs output?

748,172 MWh (2017 - 2019 actual Gross MW)

Enter the net plant heat input rate (NPHR)

9.0 MMBtu/MW (2017 - 2019 actual Gross MWh divided by 2017 - 2019 MMBtu)

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

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

Plant Elevation

607 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Sub-Bituminous ▼

Enter the sulfur content (%S) =

0.414 percent by weight

For units burning coal blends:

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

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

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

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

- Method 1  
 Method 2  
 Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{SCR}$ )	75 days (based on actual operation in 2017 - 2019)
Number of days the boiler operates ( $t_{plant}$ )	75 days (based on actual operation in 2017 - 2019)
Inlet NO <sub>x</sub> Emissions (NO <sub>x,in</sub> ) to SCR	0.317 lb/MMBtu (based on actual operation in 2017 - 2019)
Outlet NO <sub>x</sub> Emissions (NO <sub>x,out</sub> ) from SCR	0.031679 lb/MMBtu (90% control)
Stoichiometric Ratio Factor (SRF)	1.050

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

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

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

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

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

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

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

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

Select the reagent used

Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5 Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7.00	Percent	
Reagent (Cost <sub>reag</sub> )	0.293 \$/gallon for 29% ammonia*		
Electricity (Cost <sub>elect</sub> )	0.0250 \$/kWh		
Catalyst cost (CC <sub>replace</sub> )	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)		
Operator Labor Rate	60.00 \$/hour (including benefits)*		
Operator Hours/Day	4.00 hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

\* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

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

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

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

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

Maintenance and Administrative Charges Cost Factors:

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

## SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	5,862	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	5,711,520	MWh (2017 - 2019 actual Gross MW)
Estimated Actual Annual MWhs Output (Boutput) =		748,172	MWh (2017 - 2019 actual Gross MW)
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.90	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (tscr/tplant) =$	0.131	fraction
Total operating time for the SCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	1148	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	1671.30	lb/hour
Total NOx removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	958.91	tons/year
NOx removal factor (NRF) =	$EF/80 =$	1.13	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times QB \times (460 + T)/(460 + 700)n_{scr} =$	2,894,424	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	112.83	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	$14.7\ psia/P =$	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.39	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / ((1 + \text{interest rate})^Y - 1)$ , where $Y = H_{\text{catalysts}} / (t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.0497	Fraction
Catalyst volume ( $Vol_{\text{catalyst}}$ ) =	$2.81 \times Q_B \times EF_{\text{adj}} \times Slip_{\text{adj}} \times NOx_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}} / N_{\text{scr}})$	25,652.22	Cubic feet
Cross sectional area of the catalyst ( $A_{\text{catalyst}}$ ) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	3,015	ft <sup>2</sup>
Height of each catalyst layer ( $H_{\text{layer}}$ ) =	$(Vol_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{\text{SCR}}$ ) =	$1.15 \times A_{\text{catalyst}}$	3,467	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	58.9	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + H_{\text{layer}}) + 9\text{ft}$	52	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft<sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	650	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / \text{Csol} =$	2,240	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	299	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	100,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	3561.89	kW

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

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

Capital costs for the SCR ( $SCR_{cost}$ ) =	\$133,884,692	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$4,044,179	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$8,994,480	in 2019 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$191,000,000</b>	<b>in 2019 dollars</b>

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

#### SCR Capital Costs ( $SCR_{cost}$ )

For Coal-Fired Utility Boilers >25 MW:

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

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

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

SCR Capital Costs ( $SCR_{cost}$ ) = \$133,884,692 in 2019 dollars

#### Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

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

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

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

Reagent Preparation Costs (RPC) = \$4,044,179 in 2019 dollars

#### Air Pre-Heater Costs (APHC)\*

For Coal-Fired Utility Boilers >25MW:

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

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

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

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

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

#### Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

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

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

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

Balance of Plant Costs ( $BOP_{cost}$ ) = \$8,994,480 in 2019 dollars

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,775,208 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$18,042,400 in 2019 dollars
<b>Total annual costs (TAC) = DAC + IDAC</b>	<b>\$21,817,608 in 2019 dollars</b>

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	0.005 x TCI =	\$955,000 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$100,594 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$102,182 in 2019 dollars
Annual Catalyst Replacement Cost =		\$2,617,432 in 2019 dollars
For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/R_{\text{layer}}) \times \text{FWF}$	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	$B_{\text{MW}} \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$	
Direct Annual Cost =		\$3,775,208 in 2019 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$12,000 in 2019 dollars
Capital Recovery Costs (CR) =	CRF x TCI =	\$18,030,400 in 2019 dollars
<b>Indirect Annual Cost (IDAC) =</b>	<b>AC + CR =</b>	<b>\$18,042,400 in 2019 dollars</b>

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$21,817,608 per year in 2019 dollars
NOx Removed =	959 tons/year
<b>Cost Effectiveness =</b>	<b>\$22,800 per ton of NOx removed in 2019 dollars</b>

## Data Inputs

Avon Lake Power Plant Unit 9/Boiler 12

### EPA Air Pollution Control Cost Manual

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Coal ▼

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

Retrofit ▼

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

1

Complete all of the highlighted data fields:

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

652 MW (gross)

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

11,234 Btu/lb

What is the estimated actual annual MWhs output?

748,172 MWh (2017 - 2019 actual Gross MW)

Enter the net plant heat input rate (NPHR)

9.0 MMBtu/MW (2017 - 2019 actual Gross MWh divided by 2017 - 2019 MMBtu)

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

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

Plant Elevation

607 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Sub-Bituminous ▼

Enter the sulfur content (%S) =

0.414 percent by weight

For units burning coal blends:

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

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

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

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

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{SCR}$ )	75 days (based on actual operation in 2017 - 2019)
Number of days the boiler operates ( $t_{plant}$ )	75 days (based on actual operation in 2017 - 2019)
Inlet NO <sub>x</sub> Emissions (NO <sub>x,in</sub> ) to SCR	0.317 lb/MMBtu (based on actual operation in 2017 - 2019)
Outlet NO <sub>x</sub> Emissions (NO <sub>x,out</sub> ) from SCR	0.031679 lb/MMBtu (90% control)
Stoichiometric Ratio Factor (SRF)	1.050

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

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

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

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

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

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

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

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

Select the reagent used

Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5 Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7.00	Percent	
Reagent (Cost <sub>reag</sub> )	0.293 \$/gallon for 29% ammonia*		
Electricity (Cost <sub>elect</sub> )	0.0250 \$/kWh		
Catalyst cost (CC <sub>replace</sub> )	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)		
Operator Labor Rate	60.00 \$/hour (including benefits)*		
Operator Hours/Day	4.00 hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

\* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

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

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

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

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

Maintenance and Administrative Charges Cost Factors:

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

## SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	5,862	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	5,711,520	MWh (2017 - 2019 actual Gross MW)
Estimated Actual Annual MWhs Output (Boutput) =		748,172	MWh (2017 - 2019 actual Gross MW)
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.90	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (tscr/tplant) =$	0.131	fraction
Total operating time for the SCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	1148	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	1671.30	lb/hour
Total NOx removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	958.91	tons/year
NOx removal factor (NRF) =	$EF/80 =$	1.13	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times QB \times (460 + T)/(460 + 700)n_{scr} =$	2,894,424	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	112.83	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVf) =	$14.7\ psia/P =$	1.02	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.39	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / ((1 + \text{interest rate})^Y - 1)$ , where $Y = H_{\text{catalysts}} / (t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.0497	Fraction
Catalyst volume ( $Vol_{\text{catalyst}}$ ) =	$2.81 \times Q_B \times EF_{\text{adj}} \times Slip_{\text{adj}} \times NOx_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}} / N_{\text{scr}})$	25,652.22	Cubic feet
Cross sectional area of the catalyst ( $A_{\text{catalyst}}$ ) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	3,015	ft <sup>2</sup>
Height of each catalyst layer ( $H_{\text{layer}}$ ) =	$(Vol_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{\text{SCR}}$ ) =	$1.15 \times A_{\text{catalyst}}$	3,467	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	58.9	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + H_{\text{layer}}) + 9\text{ft}$	52	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft<sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	650	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / \text{Csol} =$	2,240	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	299	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	100,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

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

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	3561.89	kW

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

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

Capital costs for the SCR ( $SCR_{cost}$ ) =	\$133,884,692	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$4,044,179	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$8,994,480	in 2019 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$191,000,000</b>	<b>in 2019 dollars</b>

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

#### SCR Capital Costs ( $SCR_{cost}$ )

For Coal-Fired Utility Boilers >25 MW:

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

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

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

SCR Capital Costs ( $SCR_{cost}$ ) = \$133,884,692 in 2019 dollars

#### Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

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

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

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

Reagent Preparation Costs (RPC) = \$4,044,179 in 2019 dollars

#### Air Pre-Heater Costs (APHC)\*

For Coal-Fired Utility Boilers >25MW:

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

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

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

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

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

#### Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

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

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

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

Balance of Plant Costs ( $BOP_{cost}$ ) = \$8,994,480 in 2019 dollars

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,775,208 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$15,406,600 in 2019 dollars
<b>Total annual costs (TAC) = DAC + IDAC</b>	<b>\$19,181,808 in 2019 dollars</b>

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	0.005 x TCI =	\$955,000 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$100,594 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$102,182 in 2019 dollars
Annual Catalyst Replacement Cost =		\$2,617,432 in 2019 dollars
For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/R_{\text{layer}}) \times \text{FWF}$	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	$B_{\text{MW}} \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$	
Direct Annual Cost =		\$3,775,208 in 2019 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$12,000 in 2019 dollars
Capital Recovery Costs (CR) =	CRF x TCI =	\$15,394,600 in 2019 dollars
<b>Indirect Annual Cost (IDAC) =</b>	<b>AC + CR =</b>	<b>\$15,406,600 in 2019 dollars</b>

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$19,181,808 per year in 2019 dollars
NOx Removed =	959 tons/year
<b>Cost Effectiveness =</b>	<b>\$20,000 per ton of NOx removed in 2019 dollars</b>

**Appendix C**  
**Summary of VISTAS Visibility Modeling Results**

Table C-1 Estimated Avon Lake Power Plant Unit 9 Haze Improvements with Wet FGD (or SDA) and SNCR

	Conesville 2028 emissions modeled		Cardinal 2028 emissions modeled		Avon Lake Power Plant Unit 9 Emission Reductions Visibility Improvements			
		SO2 (tpy):	6,356	SO2 (tpy):	9,892	SO2 Controlled (tpy): 2,284 (95% SO2 Control)		
	NOX (tpy):	9,958	NOX (tpy):	4,045	NOX Controlled (tpy): 164 (SNCR: 20% NOx Control at loads >300 MW, 15.2% overall control)			
Class I Area	Total Conesville Modeled Sulfate Extinction Mm-1	Total Conesville Modeled Nitrate Extinction Mm-1	Total Cardinal Modeled Sulfate Extinction Mm-1	Total Cardinal Modeled Nitrate Extinction Mm-1	Scaled Modeled Impacts Using Conesville Results: Sulfate Extinction Mm-1	Scaled Modeled Impacts Using Conesville Results: Nitrate Extinction Mm-1	Scaled Modeled Impacts Using Cardinal Results: Sulfate Extinction Mm-1	Scaled Modeled Impacts Using Cardinal Results: Nitrate Extinction Mm-1
Brigantine WA	7.40E-02	3.90E-02	1.90E-01	1.15E-02	2.66E-02	6.42E-04	4.38E-02	4.66E-04
Dolly Sods WA	2.98E-01	2.20E-02	7.78E-01	6.60E-03	1.07E-01	3.62E-04	1.80E-01	2.68E-04
James River Face WA	1.66E-01	2.30E-02	5.20E-01	8.20E-03	5.96E-02	3.79E-04	1.20E-01	3.32E-04
Mammoth Cave NP	8.10E-02	2.80E-02	1.64E-01	1.48E-02	2.91E-02	4.61E-04	3.80E-02	6.00E-04
Otter Creek WA	2.87E-01	2.20E-02	7.27E-01	8.20E-03	1.03E-01	3.62E-04	1.68E-01	3.32E-04
Shenandoah NP	2.13E-01	1.80E-02	6.92E-01	1.80E-02	7.65E-02	2.96E-04	1.60E-01	7.30E-04

<https://www.metro4-sesarm.org/content/source-apportionment-modelingtagging>

Visibility improvement with SO2 emission controls and SNCR				
Class I Areas Nearest to the Avon Lake Power Plant	Total Haze Improvement from SO <sub>2</sub> Emission Reduction		Total Haze Improvement from NO <sub>x</sub> Emission Reduction	
	Mm <sup>-1</sup>	DV	Mm <sup>-1</sup>	DV
Brigantine WA	0.0438	0.0146	0.00047	0.00016
Dolly Sods WA	0.1797	0.0599	0.00027	0.00009
James River Face WA	0.1200	0.0400	0.00033	0.00011
Mammoth Cave NP	0.0380	0.0127	0.00060	0.00020
Otter Creek WA	0.1678	0.0559	0.00033	0.00011
Shenandoah NP	0.1598	0.0533	0.00073	0.00024

Table C-2 Estimated Avon Lake Power Plant Unit 9 Haze Improvements with Wet FGD (or SDA) and SCR

	Conesville 2028 emissions modeled		Cardinal 2028 emissions modeled		Avon Lake Power Plant Unit 9 Emission Reductions Visibility Improvements			
	SO2 (tpy):	6,356	SO2 (tpy):	9,892	SO2 Controlled (tpy): 2,284 (95% SO2 Control)			
	NOX (tpy):	9,958	NOX (tpy):	4,045	NOX Controlled (tpy): 959 (SCR Outlet: 0.07 lb/MMBtu NOx)			
Class I Area	Total Conesville Modeled Sulfate Extinction Mm-1	Total Conesville Modeled Nitrate Extinction Mm-1	Total Cardinal Modeled Sulfate Extinction Mm-1	Total Cardinal Modeled Nitrate Extinction Mm-1	Scaled Modeled Impacts Using Conesville Results: Sulfate Extinction Mm-1	Scaled Modeled Impacts Using Conesville Results: Nitrate Extinction Mm-1	Scaled Modeled Impacts Using Cardinal Results: Sulfate Extinction Mm-1	Scaled Modeled Impacts Using Cardinal Results: Nitrate Extinction Mm-1
Brigantine WA	7.40E-02	3.90E-02	1.90E-01	1.15E-02	0.02659	0.00376	0.04378	0.00273
Dolly Sods WA	2.98E-01	2.20E-02	7.78E-01	6.60E-03	0.10708	0.00212	0.17970	0.00156
James River Face WA	1.66E-01	2.30E-02	5.20E-01	8.20E-03	0.05965	0.00221	0.11999	0.00194
Mammoth Cave NP	8.10E-02	2.80E-02	1.64E-01	1.48E-02	0.02911	0.00270	0.03796	0.00351
Otter Creek WA	2.87E-01	2.20E-02	7.27E-01	8.20E-03	0.10313	0.00212	0.16776	0.00194
Shenandoah NP	2.13E-01	1.80E-02	6.92E-01	1.80E-02	0.07654	0.00173	0.15980	0.00427

<https://www.metro4-sesarm.org/content/source-apportionment-modelingtagging>

Visibility improvement with SO2 emission controls and SCR				
Class I Areas Nearest to the Avon Lake Power Plant	Total Haze Improvement from SO <sub>2</sub> Emission Reduction		Total Haze Improvement from NOx Emission Reduction	
	Mm <sup>-1</sup>	DV	Mm <sup>-1</sup>	DV
Brigantine WA	0.0438	0.0146	0.00273	0.00091
Dolly Sods WA	0.1797	0.0599	0.00156	0.00052
James River Face WA	0.1200	0.0400	0.00194	0.00065
Mammoth Cave NP	0.0380	0.0127	0.00351	0.00117
Otter Creek WA	0.1678	0.0559	0.00194	0.00065
Shenandoah NP	0.1598	0.0533	0.00427	0.00142

**Appendix D**  
**2009 Retrofit Cost Study (FGD and SCR)**

**RRI ENERGY, INC.  
FGD AND SCR RETROFIT  
BUDGETARY COST ESTIMATE & SCHEDULE  
PROJECT NUMBER 27709-269**

**AVON LAKE STATION – UNIT 9**



**VOLUME 1**

PREPARED FOR

**RRI ENERGY, INC.**

December 2009

Washington Division of URS Corporation  
510 Carnegie Center  
Princeton, NJ 08543-5287

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**ATTACHMENTS**

**VOLUME 1**

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ATTACHMENT B	COST ESTIMATE BASIS DOCUMENT
ATTACHMENT C	BUDGETARY COST ESTIMATE – FGD PROJECT ONLY

ATTACHMENT D	BUDGETARY COST ESTIMATE – SCR/AHR PROJECT ONLY
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ATTACHMENT F	CONCEPTUAL PROJECT SCHEDULES – LEVEL 1 <ol style="list-style-type: none"><li>1. FGD Project Only</li><li>2. SCR/AHR Project Only</li><li>3. Combined Project (FGD + SCR/AHR)</li></ol>
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ATTACHMENT L	BUDGETARY ZLD SYSTEM/EQUIPMENT PROPOSALS <ol style="list-style-type: none"><li>1. United Conveyor Corporation (UCC)</li><li>2. FMC</li></ol>
ATTACHMENT M	SCR SYSTEM SPECIFICATION FOR BUDGETARY PROPOSALS
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ATTACHMENT O	BUDGETARY SPECIFICATION & PROPOSALS FOR BOOSTER FANS

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## 1.0 EXECUTIVE SUMMARY

### Avon Lake Unit 9

RRI Energy Inc.'s (RRI) Avon Lake Generating Station is situated on 107 acres along the southern shore of Lake Erie, approximately 20 miles west of downtown Cleveland, Ohio.

Unit 9 is the largest of three electrical generating units at the station, with a gross generation rate of 677MW. Unit 9 began commercial operation in 1970 and provides both base load capacity and load following capability. The unit fires eastern bituminous coals and is also capable of firing a blend of PRB and bituminous coals.

### SO<sub>2</sub> Emissions Control Technology

As a result of previous screening studies, RRI Energy is considering the Limestone-Forced Oxidation (LSFO) technology as the preferred choice for future SO<sub>2</sub> emissions control on Avon Lake Unit 9.

### Environmental Concerns – Zero Liquid Discharge

In order to eliminate the environmental risks associated with discharging the wastewater that is normally produced by a LSFO system into Lake Erie, RRI specified that the FGD system design accommodate the requirement for Zero Liquid Discharge (ZLD). A ZLD system eliminates the need to consider the environmental problems associated with the disposal of contaminated process water. The ZLD technology selected for the Avon Lake Unit 9 conceptual design utilizes a blending system wherein the liquid waste stream from the process is combined with fly ash, lime, and byproduct gypsum to produce a fixated, non-leaching material that can be disposed-of in a land-fill.

### Replacement of Existing Air Preheater

As the existing horizontal shaft air preheaters on Unit 9 were reported to be reaching the end of their useful life, RRI requested that URS-Washington Division (URS) include the replacement of the air preheaters as part of the SCR project. RRI and URS mutually agreed that the preheaters should be replaced with new vertical shaft air heaters.

### Scope and Objectives of Study

The purpose of this study is to develop conceptual designs, budget cost estimates, and Level 1 schedules for the implementation of wet LSFO FGD technology and SCR NO<sub>x</sub> control technology (singly or in combination) on Avon Lake Unit 9. RRI can use the data and schedules from these cost estimates in their economic model. The model will be used to verify that these technologies meet the economic criteria that identify them as the “technologies of choice.”

The initial phase of this study included a screening analysis of commercially available NOx reduction technologies. Based on the criteria developed during the screening analysis, and input from RRI, Selective Catalytic Reduction (SCR) was identified as the candidate technology for future NOx emissions control on Avon Lake Unit 9.

### Project Scenarios Evaluated

URS was commissioned to prepare individual capital cost estimates and Level 1 schedules for the following alternative project scenarios:

- A. LSFO FGD Retrofit + ZLD Blending System (ZLDBS) - Only.
- B. SCR Retrofit + Air Heater Replacement - Only.
- C. FGD + ZLDBS + SCR + AH Replacement – Combined

URS developed capital cost estimates and schedules for each of these projects. The capital cost estimates are based on mass balances, preliminary equipment sizes and conceptual general arrangements. Budgetary quotations from potential vendors were utilized in conjunction with material quantity take-offs, to develop the capital costs for each of the alternate projects.

As a cross check, URS compared the estimates to current in-house FGD projects and found good agreement. There are no recent in-house projects available that would enable a capital cost comparison for the ZLDB system. However, URS does have extensive experience with material handling systems, which form the basis for the design of the ZLDBS.

### Estimated Capital Costs, Man-Hrs and Preliminary Schedule

Table 1.0-1 summarizes primary Cost, Man-Hr and Schedule information. Detailed information is included in Attachment C, D & E for Project Cost and Man-Hrs. Attachment F includes Level 1 schedules for the three (3) project scenarios.

	FGD Only	SCR / AHR Only	FGD + SCR / AHR
<b>Total Project Cost</b>	<b>\$389,025,574</b>	<b>\$230,214,728</b>	<b>\$609,940,378</b>
<b>Total Man-Hrs</b>	<b>1,476,943</b>	<b>970,652</b>	<b>2,419,858</b>
<b>Schedule (Months after Limited Notice to Proceed)</b>	<b>50 Months</b>	<b>46 Months</b>	<b>50 Months</b>

Table 1.0-1: Estimated Capital Cost, Man-Hrs and Schedule for Potential Project Scenarios

## 2.0 INTRODUCTION

### 2.1 Background

RRI Energy Inc. (RRI) is considering the installation (either singly or in combination) of a Flue Gas Desulfurization (FGD) System and a Selective Catalytic Reduction (SCR) System on Avon Lake Unit 9, which is a nominal 677 MW coal-fired generating unit.



Figure 2.0-1: Aerial View of Avon Lake Unit 9.

RRI commissioned URS-Washington Division (URS) to prepare a study which includes the preparation of individual cost and schedule estimates for three (3) alternate project scenarios:

- A. FGD Retrofit only.
- B. SCR retrofit only.
- C. Combined FGD and SCR retrofit projects.

The study commenced with a visit to the Avon Lake Generating Station on April 8, 2009. During the visit, URS met with RRI Engineering and Avon Lake Station personnel to review the Project's goals and objectives, the scope of the study and URS's study approach. URS also gathered pertinent operating data and station drawings relevant to the study work.

A walkdown of the station was also conducted to observe existing site conditions, access restrictions, and the condition and performance of equipment.

During the site visit, RRI expressed concern about potential restrictions regarding the discharge of process liquid wastes into Lake Erie. On April 23, RRI instructed URS to consider a FGD system with a Zero Liquid Discharge (ZLD) blending system in lieu of a waste water treatment system. The ZLD blending system results in disposable grade gypsum byproduct, consisting of a stabilized mixture of gypsum, flyash and lime

As a result of the URS site visit, results of previous screening studies, and discussions with RRI, the following assumptions were established:

- A. The FGD project will utilize Limestone-Forced Oxidation (LSFO) technology with a Zero Liquid Discharge Blending System (ZLDBS) to produce a stabilized, fixated byproduct suitable for disposal in a landfill.
- B. The SCR project will include replacement of the existing air heaters.

The complete listing of economic parameters used in the study is provided in the "Cost Estimate Basis" document which is included in Attachments B to this report. The detailed fuel specifications are provided in the "Design Basis Document" which is included as Attachment A.

The characteristics of four fuels were incorporated into calculations and mini-specifications to obtain budget estimates from potential suppliers of the major systems and BOP equipment.

### 3.0 “KEY” DESIGN DATA AND ASSUMPTIONS

Detailed design bases and assumptions that were used in the performance of this study are included in the “Design Basis Document” (Attachment A). This document lists the design bases and assumptions and also indicates the sources of critical information.

This section includes excerpts of “key” information from the Design Basis Document to provide an overview of Project requirements. In case of discrepancies, the information in the Design Basis Document that is included as Attachment A has priority over the information in this section.

#### 3.1 General Site Data

Plant Location	Approx. 20 Miles West of Cleveland. Ohio, near Avon Lake, OH
Elevation, ft above MSL	607
Design Plant Life, years	20
Design Atmospheric Pressure, in-Hg	29.03
Design Ambient Conditions:	
Dry Bulb Temperature (minimum)	-20°F.
Dry Bulb Temperature (maximum)	103°F.
Relative Humidity	51.6%
Frost Depth	4’-4” below ground surface.
Building Code IBC 2006	(2007 Ohio Building Code)
Seismic Loads (per IBC 2006)	Site Class D (URS Assumption) Seismic Design Category B

#### 3.2 Avon Lake Unit No. 9 Operating Conditions

Gross Output (MCR)	677 MW
Net Output	649 MW
Operating Mode	Load Following
Maximum Coal Feed Rate	238 Tons/hr

#### 3.3 Other AQCS Equipment on Avon Lake Unit No. 9

Dust Collection (existing)	Two (2) “Newer” ESPs replace two (2) “guttled” ESPs.
----------------------------	--

### 3.4 Licensing Considerations

FGD Plant Water Balance	Zero Liquid Discharge
SCR Reagent	19% Aqueous Ammonia

### 3.5 Site Access (FGD Process Related)

Limestone and Lime Delivery	By Truck
Equipment Delivery	By Truck
Byproduct Disposal	By Truck

### 3.6 Performance Requirements

#### 3.6.1 FGD System Related Performance Requirements

Minimum sulfur dioxide removal efficiency	98%
Maximum gypsum moisture content, % by weight	25%

#### 3.6.2 SCR System Performance Requirements

SCR Minimum NO <sub>x</sub> Removal Efficiency	90%
Maximum SCR Ammonia Slip	2%
Maximum SCR SO <sub>2</sub> → SO <sub>3</sub> Conversion	0.15% per Catalyst Layer

#### 3.6.3 Noise and Availability

Maximum noise level measured three feet from any piece of equipment	85 dBA
Minimum AQCS availability	99%

#### 3.6.4 Analyses of Coals Included in Study

Table 3.6-1 provides the ultimate analyses of the coals that were used in the performance of this study.

**TABLE 3.6-1  
 Coal Analyses**

Fuel Designation		1 (FGD Design)	2	3	4
Type		100% Eastern Bituminous "C"	100% Eastern Bituminous "B"	60% "B" + 40% PRB	60% "C" + 40% PRB
Moisture,	wt%	5.94	5.80	13.72	13.80
Carbon,	wt%	69.45	72.20	64.98	63.33
Hydrogen,	wt%	4.72	4.79	4.39	4.35
Nitrogen,	wt%	1.20	1.36	1.10	1.01
Sulfur,	wt%	4.53	2.99	1.93	2.85
Chlorine,	wt%	0.05	0.10	0.06	0.03
Oxygen,	wt%	5.79	5.05	7.47	7.92
Ash,	wt%	8.31	7.71	6.35	6.71
Total	%	100.00	100.00	100.00	100.00
HHV,	Btu/lb	12,706	13,112	11,591	11,348
SO <sub>2</sub>	lb/MMBtu	7.08	4.56	3.33	5.02

### 3.7 Conceptual Project Drawings

The conceptual project drawings and sketches included in Appendix G of this report are provided for purposes of illustration only, to convey the intended project scope of work and overall arrangement as a guide for estimating the project cost.

These include:

SK-AVL-M-001	Site Plan- Combined FGD and SCR Project
SK-AVL-M-002	SCR Plan
SK-AVL-M-003	SCR Section
SK-AVL-M-004	FGD and ZLDS Flow Diagram
SK-AVL-M-005	Demolition Drawing for Unit 9 SCR
SK-AVL-M-006	Temporary By-Pass Duct
SK-AVL-E-001	Conceptual Key Single Line Diagram

## 4.0 STAND-ALONE FGD RETROFIT PROJECT

### 4.1 FGD Process Overview for Avon Lake Unit No. 9

#### 4.1.1 General Description of the Avon Lake Unit No. 9 FGD Process

RRI has selected the Limestone-Forced Oxidation (LSFO) Flue Gas Desulfurization (FGD) system for further study on Avon Lake Unit No. 9.

The hot flue gas exiting from two (2) new ID Booster fans enters an absorber where it is contacted with a dilute slurry (typically 15%-20% suspended solids by weight) containing calcium carbonate (limestone). The dissolved SO<sub>2</sub> reacts with the calcium carbonate and oxygen (oxidation air is provided by air compressors) to form calcium sulfate (gypsum) solids in the circulating slurry.

A portion of the circulating slurry is bled to a gypsum dewatering system, which produces an unwashed 90% solids cake with the majority of water returned to the absorber system. The gypsum cake is forwarded to a Zero Liquid Discharge (ZLD) blending system for further processing.

Refer to Figure 4.1-1, the System Flow Diagram for the Avon Lake FGD system. An 11” x 17” copy of this drawing is included in Attachment G.

#### 4.1.2 General Description of the ZLD Blending Process

The Zero Liquid Discharge Blending System (ZLDBS) is an add-on process to a wet limestone Flue Gas Desulfurization (FGD) system.

High concentrations of chlorides, other dissolved solids and fines in the absorber slurry circuit, can cause corrosion of the FGD system materials of construction and can adversely affect SO<sub>2</sub> removal efficiency and the dewatering system effectiveness. Therefore, a purge water stream is directed to the waste blending system where it is combined with the other plant waste materials (fly ash and gypsum cake) and trucked off-site to a land fill for ultimate disposal. The system is characterized as Zero Liquid Discharge (ZLD) as there is no process waste water stream discharged from the plant.

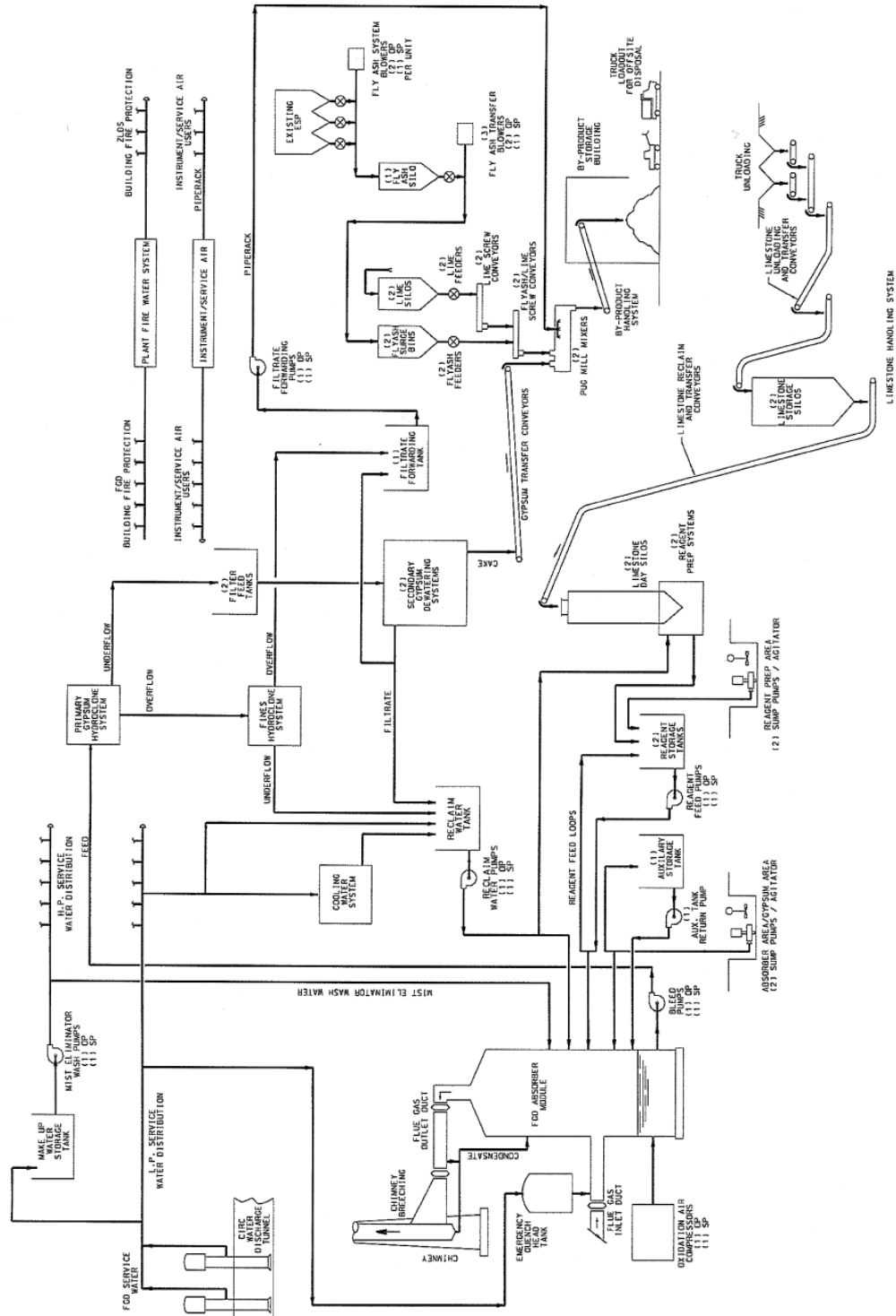
The ZLD system takes the dewatered FGD byproduct (dewatered gypsum cake), adds fly ash generated by the station, FGD process water containing dissolved solids, and quicklime (CaO) to produce a fixated byproduct suitable for a landfill. The Avon Lake ZLDB System uses unwashed FGD gypsum cake and undiluted vacuum filter filtrate as the blend water in order to remove chlorides and other dissolved solids from the absorber circuit, thereby eliminating the need for a purge waste water treatment facility.

The components of the mixture are blended in a pug mill type mixer and discharged to a temporary byproduct storage building, from which the byproduct is loaded onto trucks for transport to the landfill. Fly ash, lime and blend water are added to the pug mill mixer in ratio to measured rate of gypsum cake discharged from the vacuum filter systems. The amount of lime added to the mixture is automatically adjusted to meet the desired, preset percentage of the blend solids (nominally 1-3%).

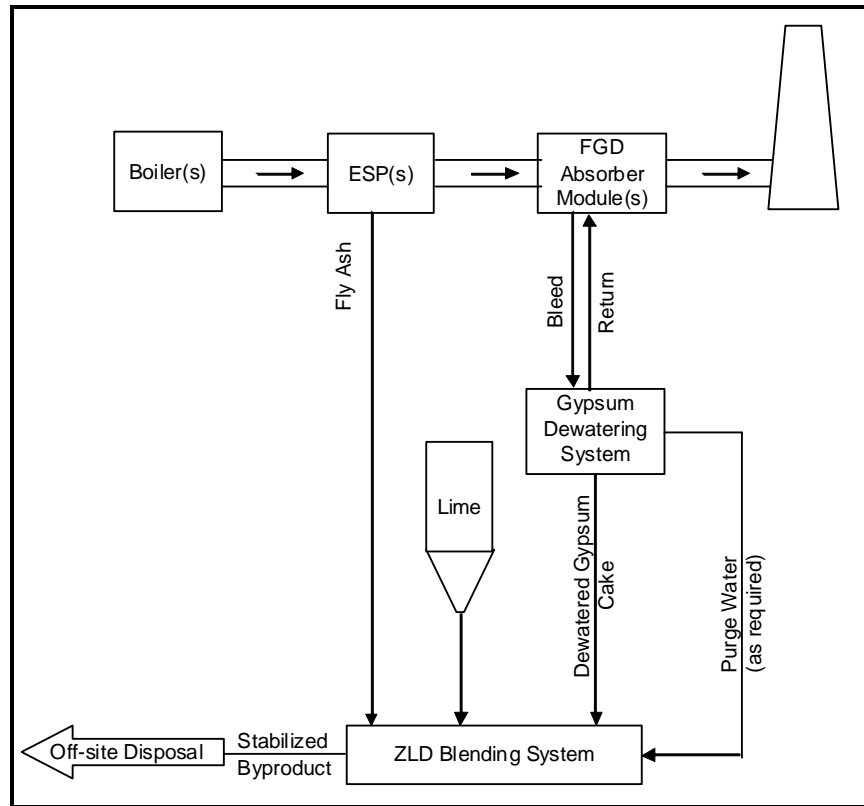
A major assumption in the design of the ZLD blending system is that it is not required to import fly ash from outside sources to be blended with the gypsum produced by the absorber. In other words, an adequate quantity of fly ash is produced at the Avon 9 Station to satisfy the requirements of the ZLD process under all operating conditions. Also, it will not be necessary to dispose of any gypsum produced by the FGD process, by methods other than ZLD blending. Thus, the amount of fly ash added by the ZLD process is adjusted automatically to ensure that all of the gypsum produced in the absorber is processed by the ZLD system.

The amount of lime added to the mixture is automatically adjusted according to the desired percentage that is set by the operator.

Diagram 4.1-2 is a schematic diagram of the type of ZLD blending system that is considered in the Avon Lake Unit 9 FGD system cost estimate:



**Figure 4.1-1: Conceptual Flow Diagram for LSF0 System Under Consideration for Retrofit on Avon Lake Unit No. 9**



**Figure 4.1-2: Schematic of a Conventional Limestone Forced Oxidation FGD System with Stabilized Sludge Byproduct from Zero Liquid Discharge Blending**

## 4.2 System and Equipment Descriptions

### 4.2.1 FGD Absorber

The maximum allowable chloride concentration in the FGD system slurry for Avon Lake Unit 9 is 30,000 ppm (for materials selection). Based on this high chloride level, a concrete absorber vessel lined with Stebbins Semplate® Ceramic Tile, was used as the basis for preparing the budgetary cost estimates for Unit 9. Also, the time required for the construction of the Stebbins Tile vessel was incorporated in the “FGD Only Project” and the “Combined SCR + FGD Project” conceptual schedules that are included in Attachment F.

### 4.2.2 Vacuum Filters

Two (2) 100 % capacity rotary drum gypsum vacuum filters; one (1) operational and one 100% spare, are sized based on 16 hours per day operation with the unit operating at MCR while firing the highest sulfur design coal, 100% of eastern bituminous coal “C” as shown in Table 3.6-1.

#### 4.2.3 Transport of Gypsum from Vacuum Filter to ZLD System Pug Mills

Based on the parameters specified in paragraph 4.2.2, gypsum is discharged from the operational vacuum filter and transported by its associated gypsum collection / transfer conveyor, G-1A or G-1B, each with actual / design capacities of 92 TPH / 120 TPH, to the inlet of the associated pug mill mixer, PMM-1A or PMM-1B.

#### 4.2.4 Transfer of Filtrate from Holding Tank to Pug Mill Spray Header

Two 100% capacity filtrate pumps, one operational and one standby, are provided to pump the filtrate from the holding tank in the ZLDBS Process Building to the pug mill mixer spray header. Each pug mill mixer is provided with four (4) parallel spray headers complete with spray nozzles, which extend the full length of the mixer. The spray headers can be isolated to allow one, two, three, or four headers to be in operation as required by the byproduct throughput in the pug mill. The spray nozzles are designed and selected to provide complete coverage of the blended mixture when any combination of spray headers is in operation in the pug mill mixer.

#### 4.2.5 Transport of Byproduct from Pug Mills to Storage Building

Based on firing 100% Century coal at MCR, the blended byproduct is discharged from the operational pug mill mixer and transported by the associated byproduct transfer conveyor, BPC-1A or BPC-1B, each with actual / design capacities of 142TPH / 200 TPH to the Byproduct Storage Building.

At the Byproduct Storage Building, the blended mixture is transferred from byproduct transfer conveyor BPC-1A or BPC-1B to the associated traveling tripper conveyor, BPC-2A or BPC-2B, which traverses the building and forms a longitudinal byproduct storage pile.

#### 4.2.6 Disposal of Byproduct

The byproduct will be stored in the building based on the curing period required to reach a fixated, stabilized product. The byproduct is then loaded by wheel loaders to disposal trucks which will transport the byproduct to a landfill disposal site.

#### 4.2.7 Fly Ash System Additions / Modifications

##### A. New Fly Ash Silo

A new Fly Ash Silo is installed to accommodate the ZLDBS Process. For the “FGD only” project configuration, the new Fly Ash Silo has a 3 day storage capacity and is located approximately 80 feet south of the ZLDBS Process Building.

Although a 24 hour capacity silo would satisfy the operational requirements of the ZLD Blending System, by installing a three day capacity silo, RRI Energy will be provided with the flexibility of installing an SCR at their discretion in the future.

B. Fly Ash Blowers and Piping

Three new (3) 50% capacity fly ash pressure blowers (two operational, 1 common spare) transport the fly ash from the existing precipitator hoppers, through new abrasion-resistant piping to the new Fly Ash Silo.

C. Existing Fly Ash Silos

Four of the six existing fly ash silos are taken out of service when the new Fly Ash Silo becomes operational.

Two of the existing fly ash silos remain in operation for the truck disposal of fly ash from the economizer/air preheater area.

D. Fly Ash Surge Bins

Fly ash is pneumatically transferred from the new Fly Ash Silo to two (2) new Fly Ash Surge Bins, located in the ZLDBS Building. Each of the surge bins has a two (2) hour capacity. A pressure transfer system is included in the budgetary cost estimate.

4.2.8 Zero Liquid Discharge System

A. Zero Liquid Discharge Blending System Process Building

The Avon Lake Zero Liquid Discharge Blending System (ZLDBS) Process Building is located on the on the east side of the Gypsum Dewatering Building as shown on drawing no. SK-AVL-M-001, Rev D, entitled “Site Plan, Combined FGD and SCR Project”, that is included in Attachment G.

The ZLDBS Process Building will house two (2) fly ash surge bins, two (2) lime silos, two (2) pug mill mixers, one (1) filtrate holding tank, two (2) filtrate pumps and the associated piping, isolation valves, rotary feeders and screw conveyors required to feed and blend the lime, fly ash, gypsum and filtrate together in the mixers to achieve a stabilized, fixated by-product.

B. Zero Liquid Discharge System Control

The range for which the ZLD system is designed is determined by the Ash to Sulfur ratio and the Chloride to Sulfur ratio of the design coals shown in Table 3.6-1. The ZLD control system is configured to automatically maintain the following conditions:

1. The maximum allowable quantity of water that is added to the mixture is 25% by weight to satisfy the structural characteristics of the fixated mixture.

2. The minimum allowable water that is added to the mixture is that required to maintain the FGD absorber circuit equilibrium chloride concentration at or below the value suitable for the absorber materials of construction and design SO<sub>2</sub> removal efficiency.

The amount of lime added to the mixture is automatically adjusted according to the desired percentage (by weight of the total mixture) that is set by the operator.

### **4.3 Materials Handling and Storage Systems**

#### **4.3.1 Limestone Handling and Storage System**

Limestone is delivered to Avon Lake in tightly covered (with tarpaulins) 25 ton capacity rear dump trucks. The trucks discharge the limestone into a 50-ton net capacity receiving hopper located approximately 200 feet north of the existing coal Crusher House.

The limestone is gravity drawn from the truck receiving hopper by two horizontal belt feeders, LBF-1A and LBF-1B, each with a design capacity range of 60 - 300 TPH. The feeders deliver the limestone to a horizontal collection conveyor, LC-1, which in turn transfers the limestone to an inclined transfer conveyor, LC-2.

Transfer conveyor LC-2 discharges the limestone to a high angle sandwich type conveyor, LC-3, which elevates and discharges the limestone through a bifurcated chute / diverter gate assembly either directly into the 15,000 ton capacity Limestone Storage Silo, LSS-1, or to a horizontal transfer conveyor, LC-3, which transfers and discharges the limestone into the 15,000 ton capacity Limestone Storage Silo, LSS-2.

With the unit operating at MCR and firing the worst case coal (100% Bituminous Coal “C”), the FGD limestone consumption rate is approximately 37.3 TPH. At this consumption rate, the total equivalent of 30,000 tons of silo storage capacity, expressed in “days of limestone consumption” for the LSFO System, is 33 days.

#### **4.3.2 Limestone Reclaim System**

Limestone reclaim from the Limestone Storage Silos is accomplished by two (2) rotary plow dischargers, RP-1A and RP-1B, located below the silos’ conical discharge hoppers. Each rotary plow has a reclaim rate of 50 – 200 TPH. The rotary plows sweep the limestone from the silo reclaim shelves and discharge it onto the horizontal limestone transfer conveyor, LC-5.

Transfer conveyor LC-5 discharges the limestone to inclined transfer conveyor LC-6 which elevates and discharges the limestone through a bifurcated chute / diverter gate assembly either directly into the Limestone Day Silo No.1, or to horizontal transfer conveyor, LC-7, which transfers and discharges the limestone into Limestone Day Silo No.2.

#### 4.3.3 Zero Liquid Discharge System

A detailed discussion of the materials handling system associated with this equipment is provided in Section 4.2.

### 4.4 **Boiler Draft System**

#### 4.4.1 Existing Flue Gas System

The existing Avon Lake Unit 9 flue gas system is described below.

##### A. Existing Air Preheaters

Flue gas leaves the economizer section of the boiler and is ducted to two (2) horizontal-shaft Air Preheaters.

##### B. Original ESPs

The heated flue gas is then ducted through two (2) “original” ESPs that have been “guttled.” The original ESPs are shown on RRI drawing 6MV-232 “Cross Section of Precipitator Bay” which is included in Attachment H.

##### C. “Newer” ESPs

The ductwork through the original ESPs is continued to two (2) “newer” ESPs that remove particulate from the flue gas. RRI drawing 6MV-0461 “Flue Gas Duct Arrangement”, which is included in Attachment H, illustrates the configuration of the newer ESPs and associated ductwork.

##### D. Existing ID Fans

As illustrated in drawing 6MV-0461, the existing ID fans are located in close proximity to the discharge of the functional ESPs.

##### E. Existing Chimney

The flue gas from the ID Fans is ducted to the existing chimney.

#### 4.4.2 Stand-Alone FGD Project Flue Gas System

##### A. Existing Air Preheaters

The “FGD Only” Project does not include replacement or upgrading of the existing Air Preheaters that are currently reported to be in poor condition.

##### B. Original ESPs

The “FGD Only” Project does not include changes to the Original ESPs or associated ductwork.

##### C. “Newer” ESPs

Modifications to the Newer ESPs are limited to the Fly Ash removal system as discussed in paragraph 4.2.7.

D. Existing ID Fans

The existing ID Fans are left as-is.

E. New Booster Fans

Two (2) new Booster Fans are installed to accommodate the increased pressure drop associated with the FGD system

F. Flue Gas Ducts

Blanking plates are installed in the existing ductwork to the existing chimney and the existing ductwork is abandoned in-place.

G. Existing Chimney

The existing chimney is abandoned in-place.

H. New “Wet” Chimney

A new concrete chimney with a single flue is required for the installation of the LSFO FGD system. In preparing the cost estimate, it is assumed that the flue is constructed of carbon steel with an interior liner of borosilicate glass.

## 4.5 Electrical and I&C Systems

### 4.5.1 Auxiliary Electrical System

The Auxiliary Power Distribution System is based on a load study including the electrical loads estimated by the various equipment vendors. The Auxiliary Power Distribution System configuration was developed based on the reliability criteria that requires that two sources of power be provided for the major buses. The electrical system is shown on the Conceptual Key Single Line Diagram, sketch #SK-AVL-E-001, included in Attachment G.

For the FGD Only retrofit scenario, the following electrical system configuration is the basis of the cost estimate:

A. New Auxiliary Transformer

One (1) new 20 kV-13.8 kV Auxiliary Transformer (970) rated 36 MVA (AA) / 45 MVA (FA) is added to serve as the normal source of power to the new FGD and Booster Fans. The new transformer is connected to the existing Unit 9 isophase bus.

B. Start-up Power

The alternate (or start-up) power supply to the FGD systems is taken from the existing Unit No. 6 13.8kV switchgear bus via existing spare breaker #647 and a new cable bus system.

C. New 13.8 kV Switchgear

One (1) new 13.8 kV Switchgear having two bus sections (Bus L-95 and L-96) is fed from the secondary of auxiliary transformer 970 via cable bus and installed in the new Main Power Distribution Center (PDC). The 13.8 kV Switchgear supplies power to the two new ID Booster Fans and to the FGD, ZLD and Material Handling Equipment loads.

D. New FGD Medium Voltage Transformers

Two (2) new 13.8 kV-4.16 kV Transformers (95 and 96), 12 MVA (AA) / 16 MVA (FA) are provided to feed the FGD 4.16kV Switchgear.

E. New FGD Medium Voltage Switchgear

One (1) new set of 4.16 kV switchgear with two bus sections (Bus H-95 and H-96) is fed from secondary transformers 95 and 96, and installed in the FGD Building to supply power to the FGD loads.

F. New FGD 480V Substation and MCCs

One (1) new 4.16 kV-480 V double-ended Unit Substation is provided and installed in the FGD Building to supply power to the 480 V FGD loads. FGD MCCs are provided and installed in the FGD Building.

G. New ZLD 480V Substation and MCCs Power Center

One (1) new 4.16 kV-480 V double-ended Unit Substation is provided and installed in the new Main Power Distribution Center to supply power to the ZLD, Fly Ash, Booster Fans and Chimney loads. ZLD MCCs are provided and installed in the ZLD Building. Booster Fan MCCs are provided and installed in the Main PDC.

H. New Material Handling 480V Substation and MCC Power Center

One (1) new 4.16 kV-480 V double-ended Unit Substation is provided and installed in the new Material Handling PDC to supply power to the Material Handling loads and the Ammonia Tank Farm loads. MCCs are provided and installed in the Material Handling PDC.

#### 4.5.2 System Instrumentation and Controls

- A. DCS Hardware and I/O cabinets are assumed to be provided by RRI under a DCS Integration contract. This DCS equipment is located in PDCs and Electrical Equipment rooms.

- B. Local PLCs with communication to the FGD/plant DCS are provided with the ZLD and MHE systems.
- C. All field instruments are provided with the FGD, ZLD and MHE systems.

#### 4.5.3 Assumptions for Cost Estimate

- A. It has been assumed that the FGD Vendor provides and installs all the electrical equipment within the FGD battery limit as required by the specification, including:
  - 1. The FGD 4.16 kV Switchgear and FGD unit substation as shown on the Key Single Line.
  - 2. All required MCCs, power and lighting panels and transformers, all power and control raceways and cables, all small power and lighting fixtures.
  - 3. All instrumentation wiring to the I/O cabinets provided by Buyer.
- B. It is assumed that the Material Handling Vendor provides and installs all the electrical equipment required in the specification, including:
  - 1. The Material Handling PDC complete with all required electrical equipment, interconnecting wiring, cable trays, etc inside the PDC.
  - 2. The Material Handling unit substation as shown on the Key Single Line.
  - 3. All required MCCs, power and lighting panels and transformers; all power and control raceways and cables; and all small power and lighting fixtures.
- C. The lengths of the plant interface cables are estimated based on assumptions regarding the locations of existing equipment.

## 4.6 **Structural Design**

### 4.6.1 Foundations

For study purposes, foundations at or 4'-0" below existing grade elevation are assumed to be bearing on rock. Shallow foundations with turndown edges are assumed to be bearing on compacted crushed stone fill.

- A. Chimney, Fly Ash Silo, and Auxiliary Tank Foundations:

These larger structures are supported on octagonal mat type foundations bearing directly on rock. Preliminary calculations indicate that rock anchors are not required to resist uplift forces.

- B. Absorber, Gypsum Dewatering Building, Reagent Building, Reclaim Water Tanks, Limestone Silos ID Booster Fans, Receiving Limestone Hopper Area and ZLD Building Foundations:

These structures are supported on rectangular mat type foundations bearing directly on rock.

C. Transformer Foundations:

Transformers are supported on concrete pedestals atop a continuous mat foundation. A continuous containment wall is provided around the perimeter of the foundation for containment of oil spills. Steel grating is installed between the transformer foundation and the containment walls.

D. By-Product Storage Building:

The pre-engineered building is supported on isolated spread footings with concrete piers. Footings bear directly on rock and are keyed into the rock to resist lateral forces. A 6'-0" high perimeter concrete push-wall is provided on three sides of the storage building, and is supported on a continuous footing, bearing directly on rock.

E. Material Handling System Supports:

Conveyor and transfer tower supports are supported on combined spread footings with concrete piers. Footings bear directly on rock.

F. Power Distribution Centers (PDCs):

The PDCs are supported on isolated spread footings with piers extending approximately 3'-0" above grade to support a structural steel frame designed to support the PDCs. Footings bear directly on rock and are keyed into the rock to resist lateral forces.

G. Miscellaneous Structures:

Miscellaneous structures are supported on turn down slab foundations. Footings bear on compacted crushed stone fill.

#### 4.6.2 Codes and Standards

It is intended that final design and construction of all work will be in accordance with current applicable laws, codes, standards, regulations and ordinances of Federal, State and local governments. A summary of the codes and industry standards applicable to the design and construction is identified, but not necessarily limited to the following list:

A. American Concrete Institute (ACI)

As applicable to reinforced concrete shell design and construction.  
313 Standard Practice for Design and Construction of Concrete Silos and Stacking Tubes for Storing Granular materials, including Commentary ACI-313R  
301 Specifications for Structural Concrete for Buildings  
304R Guide for Measuring, Mixing, Transporting and Placing Concrete

308 Specifications for Curing Concrete  
315 Detailing Reinforced Concrete Structures  
318 Building Code Requirements for Reinforced Concrete  
347 Formwork for Concrete, including Guide ACI-347R

- B. American Society of Civil Engineers
  - ASCE 7- Minimum Design Loads for Buildings and Other Structures
- C. American Society of Testing and Materials (ASTM)
  - A615 Standard Specifications for Deformed and Plain Billet-Steel Bars for Concrete Reinforcement
- D. American Welding Society (AWS)
  - D1.1 Structural Welding Code.
- E. International Code Council, Inc.
  - 2006 edition of the International Building Code (IBC)
- F. Occupational Safety and Health Administration (OSHA)
  - 29 CFR Part 1926 Occupational Safety and Health Regulation for Construction
- G. 1910 Workplace Safety Regulations
- H. Underwriters Laboratory (UL) - As applicable to systems and equipment
- I. 2007 Ohio Building Code.

## **4.7 Conceptual Construction Approach**

### **4.7.1 URS Conceptual Approach**

URS developed the following conceptual approach to construction for the Stand-Alone FGD Project to better define the project schedule, and to ensure that constructability issues are appropriately addressed. The actual construction approach will be determined by the selected FGD System supplier.

Early construction activities include setting up of temporary construction facilities such as construction office trailers, parking and laydown. In addition, any existing utilities that impact construction are relocated. It is estimated that approximately 10 acres of laydown area are required for construction.

Immediately following mobilization and set-up of temporary construction facilities, work commences on the chimney, ash silo and absorber vessel areas starting with excavation and installation of these foundations. Focus on civil works starts with the construction of the stack, absorber vessel and ash silo foundations. The majority of the remaining new foundations are completed in the first year of the construction phase of the project.

The fly ash silo with associated equipment, is the first system to be installed and functional to support relocation of the existing fly ash silo system. Coordination and scheduling of work is required with the new chimney shell construction. A prime consideration is the required exclusion zones during the placement of concrete for the chimney shell for work on the absorber erection.

Erection of the absorber vessel follows immediately after the chimney shell is completed.

Exterior work to the absorber vessel including installation of the absorber building and equipment commences after the completion of the absorber vessel. Installation of the recycle piping is coordinated with the erection of the steel structures and building around the absorber.

Where feasible, duct sections are assembled on the ground utilizing fabrication tables.

Construction utilizes various capacity cranes and lifting equipment to support the erection of the absorber, structural steel, ductwork, limestone and gypsum equipment. Preliminary analysis of the work scope indicates that three major erection cranes are required.

A Manitowoc 999 and 2250 or similar size cranes have been considered for absorber erection and ductwork installation. The duct fabrication tables are supported with 100 Ton crawler cranes.

Rough terrain cranes in capacities of 15 ton through 90 ton are utilized to supplement the larger cranes and for the movement of equipment and materials at the laydown yard area.

## **4.8 Stand-Alone FGD Project Cost Estimate**

### **4.8.1 Budgetary Cost Estimate Spreadsheets**

The spreadsheets for the Stand-Alone FGD Project Budgetary Cost Estimate are included in Attachment C.

### **4.8.2 Cost Estimate Basis Document**

The Project Cost Estimate Basis Document is included in Attachment B.

### **4.8.3 Cost Estimate Basis**

The cost estimate is based on the Site Plan for the Combined FGD and SCR Project. Should the SCR project not be required in the future, the storage requirements for fly ash can be reduced from 3-days to 1-day storage, which should result in a cost savings due to the decreased size of the new fly ash silo and its foundation.

#### 4.8.4 Assumptions for Stand Alone FGD Cost Estimate

- A. FGD system control is through a new DCS, compatible with the existing plant control system. The FGD DCS is not integrated into the existing plant DCS.
- B. New material handling systems are controlled by new PLCs.
- C. Power for the new FGD system is supplied by new auxiliary transformers.
- D. Costs for finish painting of equipment, duct and steel are included.
- E. Duct and damper installation is based on the assumption that the sections are shipped by truck to the site.
- F. Modifications to the current ash handling system are included for all three cost estimates.
- G. The new Booster Fans are sized to handle the increased draft system pressure drop. The existing FD Fans remain in place without modification.

The following items are not included in the Cost Estimate

- Asbestos abatement
- Plant licenses/permits/fees  
(a nominal allowance for engineering support is included)
- Craft busing
- Noise abatement
- Fireproofing of steel

### **4.9 Stand Alone FGD Project Schedule**

#### 4.9.1 Stand Alone FGD Project Schedule

A conceptual Level 1 schedule for the Stand Alone FGD Project is included in Attachment F.

#### 4.9.2 General

The Preliminary Project Schedule for the Stand-Alone FGD project identifies the major engineering, procurement, construction and startup activities expected to be performed from the time that Limited Notice to Proceed (LNTP) is authorized through the time that the FGD system is ready to receive flue gas. As the actual project start and required SO<sub>2</sub> compliance dates are uncertain at the time of this Report, activities are defined in months after LNTP.

#### 4.9.3 Schedule Basis

It is estimated that the FGD system will be ready to receive flue gas 50 months after LNTP, based on the following assumptions:

- A. Construction performed on a 5-day workweek throughout, except during outages.
- B. Outage work performed on 7-day work weeks utilizing multiple shifts.
- C. No work on holidays.
- D. No accommodation has been made for winter weather.
- E. No accommodation has been made for summer outage restrictions.
- F. Construction work is subcontracted (bid & award of individual subcontract packages is not shown; the schedule assumes they will be in place when needed).
- G. Assumes no piles or special design requirements are needed for foundations.

#### 4.9.4 Critical Path

The critical path is defined by procurement and erection of the FGD absorber vessel, erection of the absorber building, and installation of its equipment, piping and electrical work, final checkout of the reagent preparation and gypsum dewatering buildings, startup, and tie-in outage.

#### 4.9.5 Assumptions and Clarifications

In order to keep the foundation work for the chimney, absorber vessel and flyash silo off of the critical path, the schedule contains two Civil Contracts. The scope of the initial contract, Civil I, includes excavation and placement of large concrete foundations for these tall, heavy structures early in the project. The Civil II contract contains the excavation and placement of concrete for the balance-of plant foundations.

It is assumed that the following sections of ductwork, including expansion joints, are complete prior to the outage for the FGD tie-in:

- From the new ID fan outlet to the absorber inlet,
- From the absorber outlet to the new chimney
- From the outside face of the existing duct from the ESP to the inlet of the ID fan inlet.

Outage tie-in work includes the cut-in to existing ductwork, installation of blanking plates, turning vanes and new expansion joints.

No special cranes are required for FGD installation.

## 5.0 STAND ALONE SCR & AIR HEATER RETROFIT PROJECT

### 5.1 SCR Process Overview for Avon Lake Unit No. 9

#### 5.1.1 General Description of the Avon Lake Unit No. 9 SCR Process

RRI has selected the SCR Process for NO<sub>x</sub> emissions reduction for further study on Avon Lake Unit No. 9.

In addition to the SCR system retrofit, RRI has requested that the replacement of the existing horizontal shaft Air Preheaters be included in the SCR Retrofit Project. The existing Air Preheaters are reported to be in poor condition and are reaching the end of their useful life.

#### 5.1.2 SCR System Design Basis

The Avon Lake Unit 9 SCR will have two (2) SCR reactors. Each reactor has three (3) active layers of catalyst, and room for one (1) spare layer. The catalyst life is specified as 32,000 hours. The design NO<sub>x</sub> removal efficiency for the SCR system is 90%, and the maximum SO<sub>2</sub> to SO<sub>3</sub> conversion in the catalyst is specified as 0.15% per installed catalyst layer. The maximum ammonia slip is specified to be 2 ppm at the end of catalyst life.

The SCR process reagent is 19% aqueous ammonia, and the ammonia storage tanks are sized for a 15 day supply.

The design economizer exit temperature is 720° F based on data obtained from the Station. According to the SCR vendor whose budgetary quotation forms the basis of the cost estimate, an Economizer Bypass is not required to maintain an adequate flue gas temperature at the SCR inlet. Also, no SCR bypass is required as it is assumed that the SCR system operates year-round.

Catalyst cleaning is by Sonic Horns.

A popcorn ash catcher is included.

#### 5.1.3 Existing Avon Unit 9 Configuration

Figure 5.1-1 illustrates the ESP and Air Preheater configuration at the time that Avon Lake Unit 9 went into service. The ESP shown in this figure has been “guttled” and ductwork has been installed through it to transport the flue gas from the Air Preheater to “newer” ESPs installed downstream of the existing “boxes.”

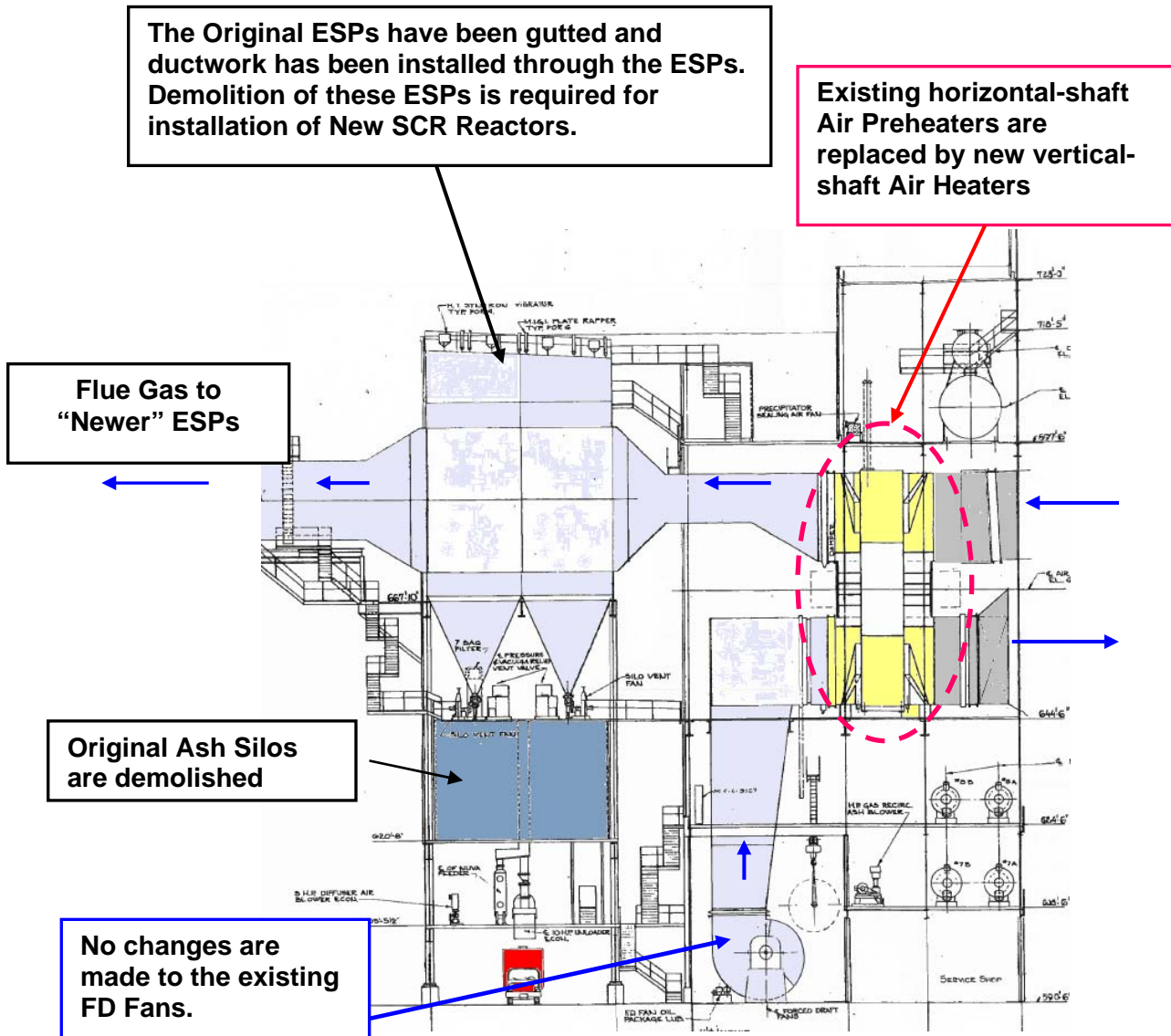


Figure 5.1-1: Original ESP and Air Preheater Arrangement on Avon Lake 9

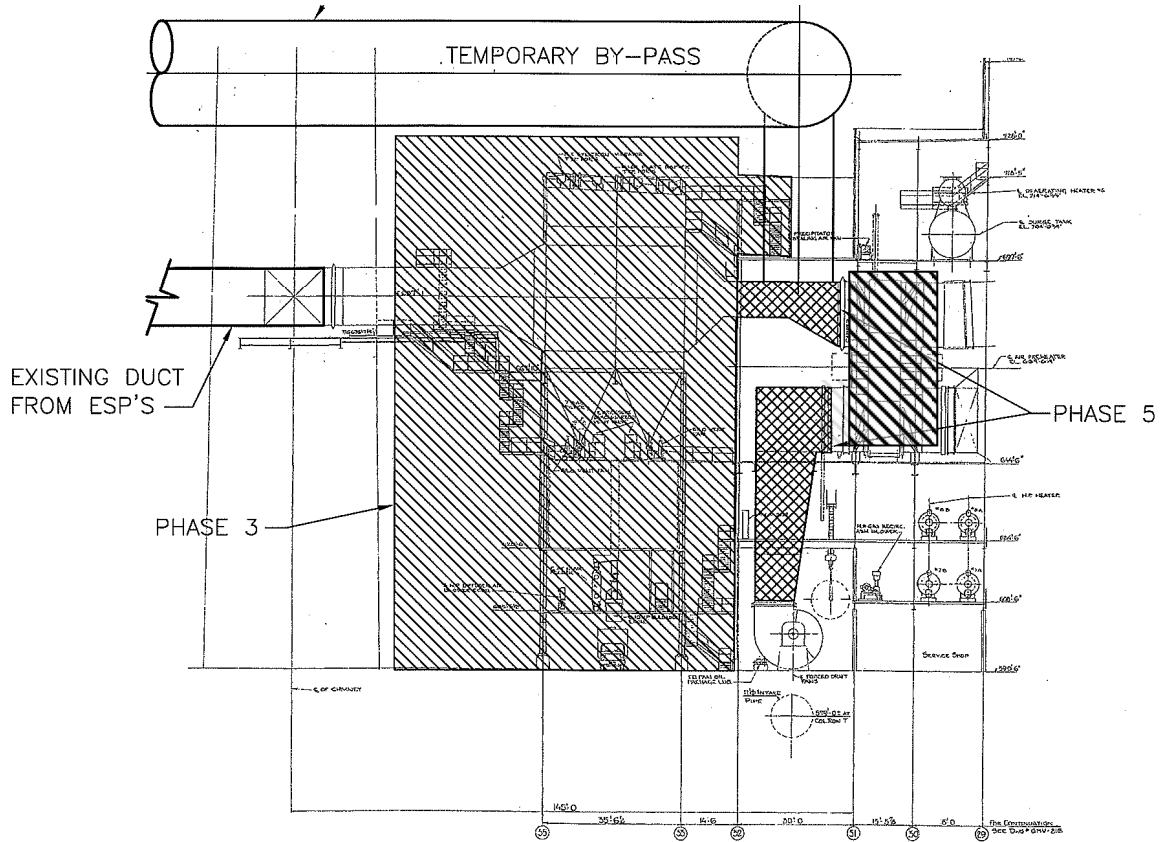


Figure 5.1-2: Original ESP and Air Preheater Arrangement on Avon Lake 9  
 Cross-Hatched Areas Indicate that Demolition is Required.



Figure 5.1-2: View of Avon Lake Unit 9 Showing Original ESPs

5.1.4 Stand-Alone SCR + AHR Retrofit – Conceptual Arrangement

Figure 5.1-2 illustrates the conceptual arrangement of the SCR Reactor and new Air Heater (and the associated ductwork) configured for the cost estimate.

The new Air Heaters are of the vertical shaft design and have superior operational characteristics to horizontal shaft Air Heaters. In addition, the vertical configuration can facilitate the installation of an SO<sub>3</sub> emissions control system in the future, if necessary.

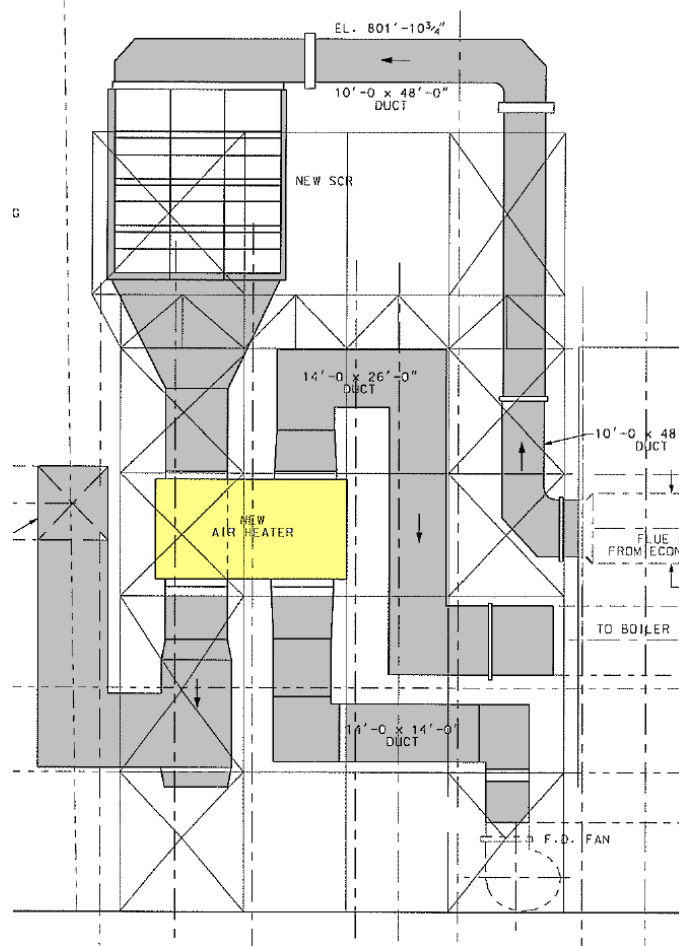


Figure 5.1-3: Original ESP and Air Preheater Arrangement on Avon Lake 9

The existing horizontal Air Preheaters are demolished. The location for the SCR requires demolition of the original ESPs (which are non-functional), and the Fly Ash Silos shown in Figure 5.1-1. A new three (3) day capacity Fly Ash Silo is installed.

## 5.2 System and Equipment Descriptions

### 5.2.1 SCR Reactors

Avon Lake Unit 9 requires two (2) SCR reactors to treat the flue gas flow from the boiler. The reactors are located in the space that the Original ESPs now occupy (reference Figures 5.1-1, 5.1-2 and 5.1-3).

The reactor casing and inlet and outlet ductwork are of carbon steel construction, and the design temperature is 800 °F. The design pressure is  $\pm$  35 in-wc.

The SCR system is designed based on using 19% aqueous ammonia as the reagent.

### 5.2.2 Ammonia System Description

The SCR system is designed based on using 19% aqueous ammonia as the reagent. The ammonia tank farm houses the storage tanks, unloading systems, and the ammonia feed pumping system. Four (4) 90,000 gallon tanks are provided to accommodate operation of the Unit at full load for 15 days, assuming the maximum ammonia consumption rate and a maximum tank volume utilization of 85%.

The ammonia injection rate at design conditions is approximately 2,860 lb/hr per reactor. A containment dike encloses the ammonia tank farm to protect against accidental spillage.

### 5.2.3 Replacement Air Heaters

## 5.3 Materials Handling and Storage Systems

### 5.3.1 Fly Ash System Additions/Modifications

#### A. Existing Fly Ash Silos

The existing Fly Ash Silos are demolished to make room for the installation of the new SCRs and Air Heaters

#### B. Existing Fly Ash Piping

The existing fly ash piping which runs from the newer ESPs to the existing fly ash silos is demolished in the area of new construction, with the balance of fly ash piping abandoned in-place.

#### C. New Fly Ash Silo

A new Fly Ash Silo is installed to replace the demolished fly ash silos. Consistent with the current design, the new Fly Ash Silo has a 3 day storage capacity and is

located south of existing newer ESPs. Truck access is provided from Lake Road for off site fly ash disposal.

D. Fly Ash Blowers and Piping

Three new (3) 50% capacity fly ash pressure blowers (two operational, one common spare) transport the fly ash from the existing precipitator hoppers, through new abrasion-resistant piping, to the new Fly Ash Silo.

Two new 100% capacity fly ash pressure blowers (one operational and one spare) transport the fly ash from the duct hoppers beneath the air heaters, through new abrasion-resistant piping to the New Fly Ash Silo.

## 5.4 Boiler Draft System

### 5.4.1 Existing Flue Gas System

The existing Avon Lake Unit 9 flue gas system is described below.

A. Existing Air Preheaters

Flue gas leaves the economizer section of the boiler and is ducted to two (2) horizontal-shaft Air Preheaters.

B. Original ESPs

The heated flue gas is then ducted through two (2) “original” ESPs that have been “guttled.” The original ESPs are shown on RRI drawing 6MV-232 “Cross Section of Precipitator Bay” which is included in Attachment H.

C. “Newer” ESPs

The ductwork through the original ESPs is continued to two (2) “newer” ESPs that remove particulate from the flue gas. RRI drawing 6MV-0461 “Flue Gas Duct Arrangement”, which is included in Attachment H, illustrates the configuration of the newer ESPs and associated ductwork.

D. Existing ID Fans

As illustrated in drawing 6MV-0461, the existing ID fans are located in close proximity to the discharge of the functional ESPs.

E. Existing Chimney

The flue gas from the ID Fans is ducted to the existing chimney.

## 5.4.2 Stand-Alone SCR + AHR Project Flue Gas System

### A. Temporary Bypass Ductwork

In order for Unit 9 to remain operational during demolition of the original ESP and installation of the new Air Heater and SCR boxes, a Temporary Bypass Duct is installed around the area of new construction, and remains in service until the SCR and replacement Air Heaters are ready for tie-in.

### B. Existing Air Preheaters

The Project includes replacement of the existing Air Preheaters that are currently reported to be in poor condition. The air preheaters will be dismantled and replaced with a section of duct during the outage prior to placing the SCR and Air Heaters in service.

### C. Original ESPs

The original, abandoned ESPs are demolished. Existing Ductwork in the area of new construction is also demolished.

### D. “Newer” ESPs

Modifications to the Newer ESPs are limited to the Fly Ash removal system as discussed in Section 5.3.1.

### E. Existing ID Fans

The existing ID Fans are modified to accommodate the added pressure drop due to the SCRs and Air Heaters. New motors are required for the upgraded ID fans.

### F. Booster Fans

Booster fans are not included.

### G. Flue Gas Ducts

Existing flue gas ducts downstream of the replacement Air Heaters to the inlets of the Newer ESPs remain in service. Likewise, existing ductwork from the outlets of the Newer ESPs to the existing stack remain in service.

### H. Existing Chimney

The existing chimney remains in service.

## 5.5 **Electrical and I&C Systems**

### 5.5.1 Auxiliary Electrical System

The electrical system is shown on the Conceptual Key Single Line Diagram, sketch #SK-AVL-E-001, included in Attachment G.

For the SCR /AHR Only retrofit scenario, the following electrical system configuration is the basis of the cost estimate:

A. SCR 480V Loads

The SCR 480 V loads are supplied from existing 480 V switchgear buses via new 480V switchgear breakers. The SCR MCC's are installed in the SCR PDC.

B. Ammonia System 480 V Loads

The Ammonia 480 V loads are supplied from the existing plant 480 V source via cable tray system run on existing pipe rack. An Ammonia MCC or PDP is installed in the Ammonia PDC.

C. Fly Ash Silo Loads

The Fly Ash Silo loads are fed from existing plant 480 V sources via overhead cable tray and underground cable systems. A Fly Ash Silo PDC is supplied to house the MCCs and miscellaneous electrical equipments and is installed in the vicinity of the Fly Ash Silo.

D. Loads due to Existing, Upgraded ID Fans

The upgraded existing ID Fans are fed from the same existing sources.

5.5.2 System Instrumentation and Controls

A. DCS Hardware and I/O cabinets are assumed to be provided by RRI under a DCS Integration contract. This DCS equipment is located in PDCs and Electrical Equipment rooms.

B. All field instruments are provided with the SCR system.

5.5.3 Assumptions for Cost Estimate

A. The SCR Vendor provides and installs the electrical equipment within the SCR battery limit as required by the specification, including:

1. The SCR PDC complete with all required electrical equipment, interconnecting wiring, cable trays, etc inside the PDC;
2. All required MCC's, power and lighting panels and transformers, all power and control raceways and cables, all small power and lighting fixtures.
3. All instrumentation wiring to the I/O cabinets provided by Buyer.

B. The SCR Vendor provides the Ammonia PDC complete with all required electrical equipment, interconnecting wiring, cable trays, etc inside the PDC.

- C. Adequate spare capacity and spare spaces or breakers are available at the existing 480V unit substations/load centers to supply power to the SCR, Ammonia Tank Farm and Fly Ash Silo loads.
- D. The lengths of the plant interface cables are estimated based on assumptions regarding the existing equipments locations within the plant.
- E. Regarding the existing ID fans to be upgraded:
  - 1. Tthe upgraded ID fans are fed from the same existing sources. New cables and cable trays will be provided.
  - 2. Fan auxiliary equipment is replaced and new wiring and raceways are included.

## 5.6 Structural Design

### 5.6.1 Foundations

For study purposes, foundations at or 4'-0" below existing grade elevation are assumed to be bearing on rock. Shallow foundations with turndown edges are assumed to be bearing on compacted crushed stone fill.

#### A. SCR Foundations:

The SCR structure is supported on 3 rows of 4 columns each for a total of 12 columns. Each row of columns is supported on an 85 ft long by 10 ft wide by 4'-6" continuous strip footing, which bears directly on rock. Concrete piers sit atop the strip footings and extend 3'-0" above slab on grade elevations to support the structural steel columns. Preliminary calculations indicate that rock anchors are not required to resist uplift forces.

Absorber, Gypsum Dewatering Building, Reagent Building, Reclaim Water Tanks, Limestone Silos ID Booster Fans, Receiving Limestone Hopper Area and ZLD Building Foundations:

These structures are supported on a rectangular mat type foundations bearing directly on rock.

#### B. Ammonia Tanks Foundation:

The ammonia tanks are supported on octagonal concrete piers atop continuous mat foundation with a continuous containment wall around the perimeter of the foundation to provide containment of any ammonia spills. The mat foundation is bears on rock

#### C. Transformer Foundations:

Transformers are supported on concrete pedestals atop a continuous mat foundation. A continuous containment wall is provided around the perimeter of the foundation

for containment of oil spills. Steel grating is installed between the transformer foundation and the containment walls.

D. Power Distribution Centers (PDCs):

The PDCs are supported on isolated spread footings with piers extending approximately 3'-0" above grade to support a structural steel frame designed to support the PDC's. Footings bear directly on rock and are keyed into the rock to resist lateral forces.

E. Miscellaneous Structures:

Miscellaneous structures are supported on turn down slab foundations. Footings bear on compacted crushed stone fill.

## 5.6.2 Structures

A. Temporary By-pass Structure

In order for Unit 9 to remain operational during demolition and installation of the new SCR and air heater, a temporary by-pass duct is installed around the demolition / construction area.

Two 18' diameter ducts are installed directly to the outlet ducts of the existing air preheaters, between column lines 31 and 32, and extend upward through the existing air heater roof located at elevation 697'. At that point, they connect to a 27' diameter duct installed at elevation 745'.

The 27' duct runs in the North to South direction from column line P to column line J. The duct then turns to the West (south of column line J) from column lines 32 through 37. This section of temporary duct is supported off of the existing air heater structure by extending some of the existing building columns and providing new structural framing at elevation 728'. At the turbine building, the duct is supported using long span trusses which are supported by existing turbine building columns which are extended, braced and reinforced to support the trusses.

The 27' diameter temporary by-pass duct west of column line 37 branches out into two 18' diameter ducts; one is connected to the existing precipitator "B" duct, and the other one runs North on the west side of the existing chimney and connects to the existing precipitator "A" duct. The 18' diameter ducts are supported by extending the existing precipitator duct supports and providing new supports off the existing chimney.

For study purposes, it is assumed that no modifications to the existing turbine building foundations and existing duct precipitator support foundations are required for the installation of the temporary by-pass duct.

The temporary duct is installed pre-outage with tie-ins made and blanking plates installed during a scheduled outage.

## B. SCR Structure

The (2) SCR reactor boxes, (2) New Air Heaters, and Inlet and Outlet Ducts, are supported on a braced structure conformed by (3) rows of 4 columns each for a total of 12 columns.

Long span trusses are used to support the SCR reactors at elevation 741'-0" (approximately 150'-6" above grade) and the Air Heaters at elevation 666'-0" (approximately 76'-0" above grade). As the wind "sail" area in the east-west direction remains essentially unchanged, it has been assumed that SCR structure can safely transfer east-west horizontal forces (wind and seismic) to the existing boiler structure. The preliminary design of the SCR structure is considered to fully resist wind and seismic forces in the north-south direction.

Access platforms with metal grating are included at the following floor elevations: 780'-0", 741'-0", 728'-0", 700'-0", 666'-6", 644'-6" and 724'-0". Two stair towers provide access to the above platforms. Platforms around the SCR reactors are included with the vendor's equipment

### 5.6.3 Codes and Standards

It is intended that final design and construction of all work will be in accordance with current applicable laws, codes, standards, regulations and ordinances of Federal, State and local governments.

A summary of the codes and industry standards applicable to the design and construction is identified in Section 4.6.2.

## 5.7 **Conceptual Construction Approach**

### 5.7.1 URS Conceptual Construction Approach

URS developed the following conceptual approach to construction for the Stand-Alone SCR + Air Heater Project to better define the project schedule and to ensure that constructability issues are appropriately addressed. The actual construction approach will be determined by the selected SCR System supplier.

#### A. Early Construction Activities

Early construction activities will include setting up of temporary construction facilities such as construction office trailers, parking, and laydown (see Figure 5.7-1). In addition, any existing utilities that will impact construction will be relocated. It is estimated that approximately 12 acres of laydown area will be required for construction.

Immediately following mobilization and set-up of temporary construction facilities, work will commence on installation of the new fly ash system and installation of the temporary by-pass ductwork. Installation of the fly ash system includes new foundations, fly ash silo, routing of new fly ash piping, associated equipment and power and controls. Installation of the by-pass duct will include all associated support steel and duct short of tie-in to existing plant equipment.

#### B. Cranes

Due to the limited access and multiple conveyors in the vicinity of the SCR and new Air Heater locations, two (2) construction tower cranes will be utilized to support construction. These tower cranes will be of type FMC Link Belt series TG or Favelle Favco M1280D & M760D series cranes. One crane will be located on the north side of the existing boiler house, and the other is located south of the SCR adjacent to the boiler and turbine building.

#### C. Execution of Construction

The construction execution can be broken down into 6 phases as follows:

##### 1. Phase 1

- Install Bypass ductwork.

##### 2. Phase 2 (Outage #1)

- Tie-in bypass duct to existing plant equipment.
- Tie-in existing fly ash piping to new fly ash system.

##### 3. Phase 3

- Demolition of existing fly ash silo.
- Demolition of abandoned ESP steel and foundations.
- Close in Boiler House wall along CL32 with siding.

##### 4. Phase 4

- Install SCR support steel.
- Install new Air Heater.
- Install SCR and associated equipment.

5. Phase 5 (Outage #2)

- Remove temporary by-pass duct.
- Remove duct sections between FD fan and existing air preheater inlet
- Remove duct sections between existing air preheater outlet to abandoned ESP inlet.
- Remove existing air preheater internals.

6. Phase 6

- Install air preheater division plates.
- Tie-in new duct to SCR and new air heater.

Where feasible, duct sections will be assembled on the ground utilizing fabrication tables. The duct fabrication tables will be supported with 100 Ton crawler cranes.

Rough terrain cranes in capacities of 15 ton through 90 ton will be utilized to supplement the larger cranes and for the movement of equipment and materials at the laydown yard area.

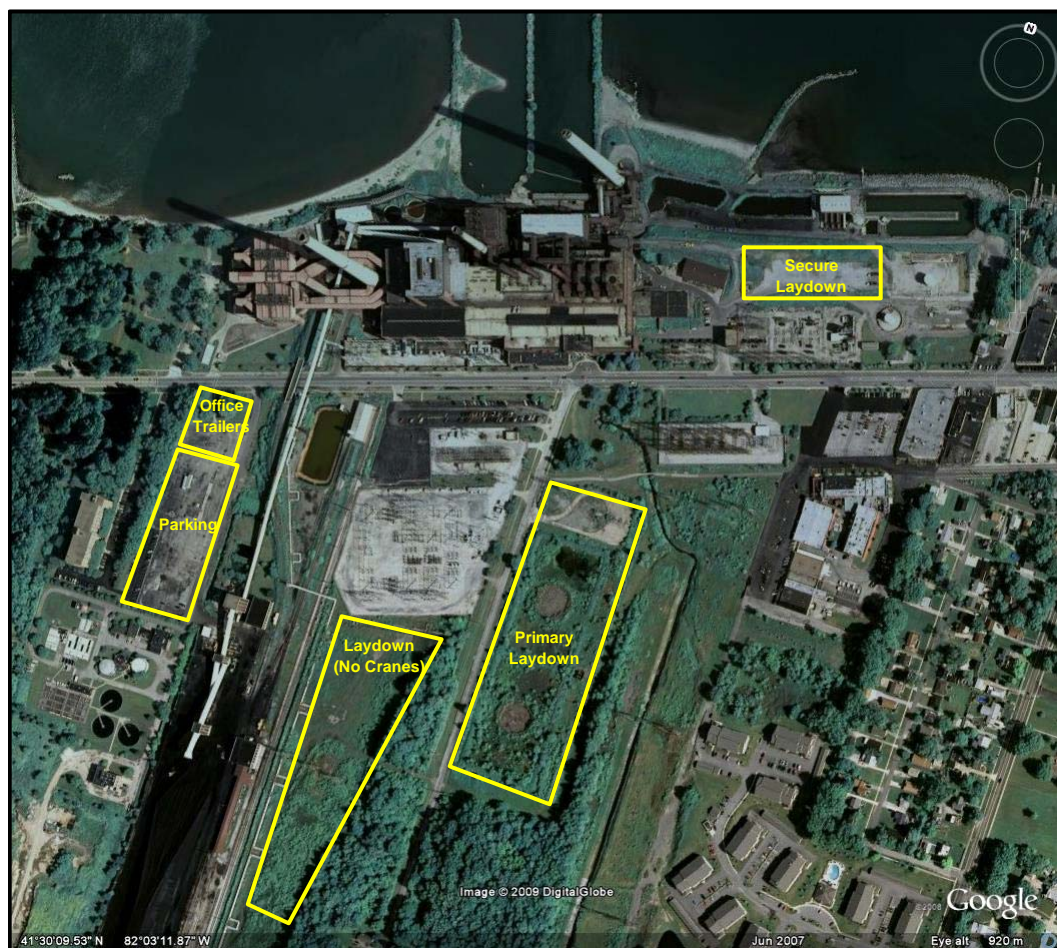


Figure 5.7-1: Construction laydown areas, parking and office trailer locations.

## **5.8 Stand-Alone SCR + AHR Project Cost Estimate**

### **5.8.1 Budgetary Cost Estimate Spreadsheets**

The spreadsheets for the Stand-Alone SCR + AHR Project Budgetary Cost Estimate are included in Attachment D.

### **5.8.2 Cost Estimate Basis Document**

The Project Cost Estimate Basis Document is included in Attachment B.

### **5.8.3 Cost Estimate Basis**

The cost estimate is based on the Site Plan for the Combined FGD and SCR Project. Should the FGD project not be required in the future, the size of the new fly ash silos will remain the same. However, the location of the new fly ash silo and aqueous ammonia storage tank area can be moved closer to the main plant, which provides a cost savings in piping, wiring, raceways and structural supports.

### **5.8.4 Assumptions for Stand Alone SCR + AHR Cost Estimate**

- A. The up-grade of existing fans will not change the size or loading of the foundation.
- B. It has been assumed that adequate spare capacity and spare spaces or breakers are available at the existing 480V unit substations/load centers to supply power to the SCR and Ammonia Tank farm loads.
- C. It has been assumed that the upgraded ID fans will be fed from the same existing sources. New cables and cable trays are included.
- D. It has been assumed that all of the fan auxiliary equipment will be replaced and will require new wiring and raceways. Costs for finish painting of equipment, duct and steel are included.
- E. Duct and damper installation is based on the assumption that the sections are shipped by truck to the site.
- F. Modifications to the current ash handling system are included for all three cost estimates.
- G. Modified ID Fans handle the increased draft system pressure drop. The existing FD Fans remain in place and do not require modification. The cost of modifications to the FD fan outlets and ductwork to accommodate the new air heaters is included.

H. It is assumed that the SCR Vendor provides and installs all the electrical equipment within the SCR battery limit, including:

- The SCR PDC complete with all required electrical equipment, interconnecting wiring, cable trays, etc inside the PDC;
- All required MCC's, power and lighting panels and transformers, all power and control raceways and cables, all small power and lighting fixtures;
- All instrumentation wiring to the I/O cabinets is provided by Buyer.
- The Ammonia PDC complete with all required electrical equipment, interconnecting wiring, cable trays, etc inside the PDC.

The following Items are not included in the Cost Estimates:

- Asbestos abatement
- Plant licenses/permits/fees  
(a nominal allowance for engineering support is included)
- Craft busing
- Noise abatement
- Fireproofing of steel

## **5.9 Stand Alone SCR + AHR Project Schedule**

### 5.9.1 Stand Alone SCR + AHR Project Schedule

A conceptual Level 1 schedule for the Stand Alone SCR + AHR Project is included in Attachment F.

### 5.9.2 General

The Preliminary Project Schedule for the Stand-Alone SCR + AHR project identifies the major engineering, procurement, construction and startup activities expected to be performed from the time that Limited Notice to Proceed (LNTP) is authorized through the time that the SCR system is ready to receive flue gas. As the actual project start and required NOx emissions compliance dates are uncertain at the time of this Report, activities are defined in months after LNTP.

### 5.9.3 Schedule Basis

It is estimated that the SCR system and Air Heaters will be ready to receive flue gas 46 months after LNTP, based on the following assumptions:

- A. Construction performed on a 5-day workweek throughout, except during outages.

- B. Outage work performed on 7-day work weeks utilizing multiple shifts.
- C. No work on holidays.
- D. No accommodation has been made for winter weather.
- E. No accommodation has been made for summer outage restrictions.
- F. Construction work is subcontracted (bid & award of individual subcontract packages is not shown; the schedule assumes they will be in place when needed).
- G. Assumes no piles or special design requirements are needed for foundations.

#### 5.9.4 Critical Path

The critical path is defined by procurement of the SCR, design, fabrication and installation of building steel reinforcements, installation off the fly ash silo, outage tie-in (Month 26) of the fly ash silo and temporary bypass duct, mitigate and abate the abandoned ESP area, demolition of the abandoned ESP steel and foundations, installation of SCR foundations, support steel, replacement air heaters, ductwork and SCR boxes, piping and electrical systems, outage (Months 42-44) for the removal of temporary bypass duct and existing air preheater internals, installation of baffle plate in air preheater, complete ductwork installation, complete tie-in connections, test and startup.

#### 5.9.5 Assumptions and Clarifications

Two (2) tower cranes, type FMC's Link Belt series TG, will be utilized for the SCR and AHR erection. One crane will be located on the north side of existing boiler house, and the second located south of the SCR's, adjacent to the boiler and turbine building. Outage tie-in work includes the cut-in to existing ductwork, installation of blanking plates, turning vanes and new expansion joints.

## 6.0 COMBINED FGD AND SCR & AHR RETROFIT PROJECT

### 6.1 Process Overviews for Avon Lake Unit No. 9

#### 6.1.1 Avon Lake Unit No. 9 FGD Process Overview

The Avon Lake Unit No. 9 FGD process, and related systems and equipment are described in Sections 4.1 through 4.3.

#### 6.1.2 Avon Lake Unit 9 SCR Process Overview

The Avon Lake Unit No. 9 SCR process equipment descriptions are described in Sections 5.1 and 5.2.

### 6.2 Boiler Draft System

#### 6.2.1 Existing Flue Gas System

The existing Avon Lake Flue Gas System is as described in Section 4.4.1.

#### 6.2.2 Combined FGD / SCR Project Flue Gas System

##### A. Existing Air Preheaters (replaced)

The Project includes replacement of the existing Air Preheaters that are currently reported to be in poor condition. The original horizontal-shaft Preheaters are replaced with vertical shaft Air Heaters.

##### B. Original ESPs

The Project requires that the existing (non-functional) ESPs be demolished to provide space for the installation of the new Air Heaters and SCR reactors.

##### C. “Newer” ESPs

Modifications to the Newer ESPs are limited to the Fly Ash removal system as discussed in paragraph 4.2.7.

##### D. Existing ID Fans

The existing ID Fans are left as-is.

##### E. New Booster Fans

Two (2) new Booster Fans are installed to accommodate the increased pressure drop associated with the FGD, SCR and New Air Heaters.

##### F. Flue Gas Ducts

Blanking plates are installed in the existing ductwork to the existing chimney and the existing ductwork is abandoned in-place.

G. Existing Chimney

The existing chimney is abandoned in-place.

H. New “Wet” Chimney

A new concrete chimney with a single flue is required for the installation of the LSFO FGD system. In preparing the cost estimate, it is assumed that the flue is constructed of carbon steel with an interior liner of borosilicate glass.

### 6.3 Fly Ash System Modifications

A. Existing Fly Ash Silos

The existing Fly Ash Silos are demolished to make room for the installation of the new SCRs and Air Heaters

B. Existing Fly Ash Piping

The existing fly ash piping which runs from the newer ESPs to the existing fly ash silos is demolished in the area of new construction, with the balance of fly ash piping abandoned in-place.

C. New Fly Ash Silo

A new Fly Ash Silo is installed to replace the demolished fly ash silos. Consistent with the current design, the new Fly Ash Silo has a 3 day storage capacity and is located south of existing newer ESPs. Truck access is provided from Lake Road for off site fly ash disposal.

D. Fly Ash Blowers and Piping

Three new (3) 50% capacity fly ash pressure blowers (two operational, 1 common spare) transport the fly ash from the existing precipitator hoppers, through new abrasion-resistant piping, to the new Fly Ash Silo.

Two new 100% capacity fly ash pressure blowers (one operational and one spare) transport the fly ash from the duct hoppers beneath the air heaters, through new abrasion-resistant piping, to the New Fly Ash Silo.

## 6.4 Electrical and I&C Systems

### 6.4.1 New Auxiliary Power Distribution System

The proposed Auxiliary Power Distribution System is based on a load study including all the electrical loads as estimated by the various equipment vendors. The Auxiliary Power Distribution System configuration was developed based on the reliability criteria that require that two sources of power are provided for the major buses. The electrical system is shown on the Conceptual Key Single Line Diagram, sketch #SK-AVL-E-001.

The following electrical configuration is included:

#### A. New Auxiliary Transformer

One (1) new 20 kV-13.8 kV Auxiliary Transformer (970) rated 36 MVA (AA) / 45 MVA (FA) is added to serve as the normal source of power to the new FGD and Booster Fans. The new transformer is connected to the existing Unit 9 isophase bus.

#### B. Start-up Power

The alternate (or start-up) power supply to the FGD systems is taken from the existing Unit No. 6 13.8kV switchgear bus via existing spare breaker #647 and new cable bus system.

#### C. New 13.8 kV Switchgear

One (1) new 13.8 kV Switchgear having two bus sections (Bus L-95 and L-96) is fed from the secondary of auxiliary transformer 970 via cable bus and installed in the new Main Power Distribution Center (PDC). The 13.8 kV Switchgear supplies power to the two new ID Booster Fans and to the FGD, ZLD and Material Handling Equipment loads.

#### D. New FGD Medium Voltage Transformers

Two (2) new 13.8 kV-4.16 kV Transformers (95 and 96), 12 MVA (AA) / 16 MVA (FA) is provided to feed the FGD 4.16kV Switchgear.

#### E. New FGD Medium Voltage Switchgear

One (1) new set of 4.16 kV switchgear with two bus sections (Bus H-95 and H-96) is fed from the secondary transformers 95 and 96 and is installed in the FGD Building to supply power to the FGD loads.

F. New FGD 480V Substation and MCCs

One (1) new 4.16 kV-480 V double-ended Unit Substation are installed in the FGD Building to supply power to the 480 V FGD loads. FGD MCCs are provided and installed in the FGD Building.

G. New ZLD 480V Substation and MCCs Power Center

One (1) new 4.16 kV-480 V double-ended Unit Substation is installed in the new Main Power Distribution Center to supply power to the ZLD, Fly Ash, Booster Fans and Chimney loads. ZLD MCCs are installed in the ZLD Building. Booster Fan MCCs are installed in the Main PDC.

H. New Material Handling 480V Substation and MCC Power Center

One (1) new 4.16 kV-480 V double-ended Unit Substation is installed in the new Material Handling PDC to supply power to the Material Handling loads and the Ammonia Tank Farm loads. MCCs are installed in the Material Handling PDC.

I. New SCR 480V MCC Power Center

The SCR 480 V loads are supplied from existing 480 V switchgear buses via new 480V switchgear breakers. The SCR MCCs are installed in the SCR PDC.

J. New Ammonia 480V MCC Power Center

The Ammonia 480 V loads are supplied from the new Material Handling 480 V unit substation buses. An Ammonia MCC or PDP is installed in the Ammonia PDC.

6.4.2 System Instrumentation and Controls

- A. DCS Hardware and I/O cabinets are provided by RRI under a DCS Integration contract. This DCS equipment is located in PDCs and Electrical Equipment rooms.
- B. Local PLCs with communication to the FGD/plant DCS are provided with the ZLD and MHE systems.
- C. All field instruments are provided with the FGD, ZLD and MHE systems.

6.4.3 Assumptions for Cost Estimate

- A. It is assumed that the FGD Vendor provides and installs all electrical equipment within the FGD battery limit as required by the specification, including:
  - 1. The FGD 4.16 kV Switchgear and FGD unit substation as shown on the Key Single Line;
  - 2. All required MCCs, power and lighting panels and transformers, all power and control raceways and cables, all small power and lighting fixtures;

3. All instrumentation wiring to the I/O cabinets provided by Buyer.
- B. It is assumed that the SCR Vendor provides and install all the electrical equipment within the SCR battery limit as per the specification, including:
1. The SCR PDC complete with all required electrical equipment, interconnecting wiring, cable trays, etc inside the PDC.
  2. All required MCCs, power and lighting panels and transformers, all power and control raceways and cables, all small power and lighting fixtures.
  3. All instrumentation wiring to the I/O cabinets provided by Buyer.
- C. It is assumed that the SCR Vendor provides the Ammonia PDC complete with all required electrical equipment, interconnecting wiring, cable trays, etc inside the PDC.
- D. It is assumed that the Material Handling Vendor provides and install all the electrical equipment as per the specification, including:
1. The Material Handling PDC complete with all required electrical equipment, interconnecting wiring, cable trays, etc inside the PDC;
  2. The Material Handling unit substation as shown on the Key Single Line;
  3. All required MCCs, power and lighting panels and transformers, all power and control raceways and cables, all small power and lighting fixtures.
- E. It has been assumed that adequate spare capacity and spare spaces or breakers are available at the existing 480V unit substations/load centers to supply power to the SCR loads.
- F. The lengths of the plant interface cables are estimated based on assumptions regarding the existing equipments locations within the plant.

## 6.5 Conceptual Construction Approach

### 6.5.1 URS Conceptual Approach

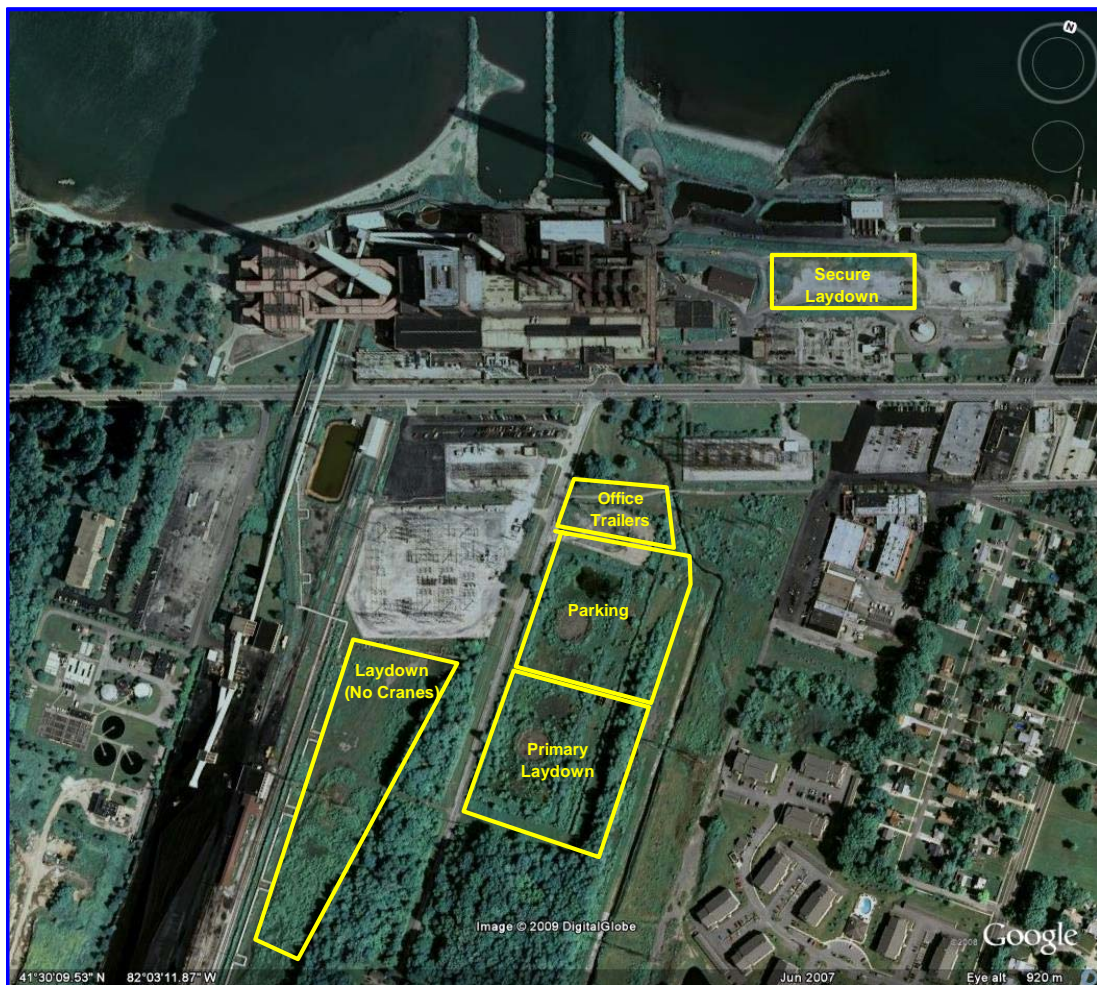
Since the majority of the work scope is located in two separate areas, it is possible to combine both the FGD and SCR/AH projects. A combined FGD and SCR/AH project could benefit the project by reducing the construction overhead costs. However, the following issues need to be taken into consideration:

#### A. Construction Parking and Facilities

Construction parking and facilities to support the larger number of peak labor force must be confirmed to be adequate. An off-site or remote craft parking area will be needed. Bussing of craft workers may be necessary at certain phases of the project.

#### B. Construction Laydown

It is estimated that approximately 20 to 25 acres of laydown is necessary to support this project. It may be necessary to acquire off-site or remote laydown areas.



## 6.6 Combined FGD and SCR / AHR Project Cost Estimate

### 6.6.1 Budgetary Cost Estimate Spreadsheets

The spreadsheets for the Combined FGD + SCR / AHR Project Budgetary Cost Estimate are included in Attachment E.

### 6.6.2 Cost Estimate Basis Document

The Project Cost Estimate Basis Document is included in Attachment B.

### 6.6.3 Cost Estimate Basis

The cost estimate is based on the Site Plan for the Combined FGD and SCR Project. Should the SCR project not be required in the future, the storage requirements for fly ash can be reduced from 3-days to 1-day storage, which should result in a cost savings due to the decreased size of the new fly ash silo and its foundation.

### 6.6.4 Assumptions for the Combined FGD + SCR / AHR Cost Estimate

- A. FGD system control is through a new DCS, compatible with the existing plant control system. The FGD DCS is not integrated into the existing plant DCS.
- B. New material handling systems are controlled by new PLCs.
- C. Power for the new FGD system is supplied by new auxiliary transformers.
- D. Costs for finish painting of equipment, duct and steel are included.
- E. Duct and damper installation is based on the assumption that the sections are shipped by truck to the site.
- F. Modifications to the current ash handling system are included for all three cost estimates.
- G. Modified ID Fans or new Booster Fans are sized to handle the increased draft system pressure drop. The existing FD Fans remain in place and do not require modification. The cost of modifications to the FD fan outlets and ductwork to accommodate the new air heaters is included.

The following Items are not included in the Cost Estimates:

- Asbestos abatement
- Plant licenses/permits/fees  
(a nominal allowance for engineering support is included)

- Craft busing
- Noise abatement
- Fireproofing of steel

## **6.7 Combined FGD + SCR / AHR Project Schedule**

### 6.7.1 Combined FGD + SCR / AHR Project Schedule

A conceptual Level 1 schedule for the Stand Alone FGD Project is included in Attachment F.

### 6.7.2 General

The Preliminary Project Schedule for the Combined FGD and SCR/AHR Project identifies the major engineering, procurement, construction and startup activities expected to be performed from the time that Limited Notice to Proceed (NTP) is authorized through the time that the FGD systems, the SCR systems and replacement Air Heaters are ready to place into service.

### 6.7.3 Schedule Basis

As the actual project start and required SO<sub>2</sub> and NO<sub>x</sub> compliance dates are uncertain at the time of this Report, activities are defined in months after LNTP. On the basis that both projects are authorized to commence concurrently, the overall project schedule for the combined project is governed by the project with the longest schedule, the FGD Project, which will be ready to receive flue gas 50 months after LNTP, based on the criteria set forth in Sections 4.9.3 and 5.9.3.

### 6.7.4 Critical Path

The critical path is defined by procurement and erection of the FGD absorber vessel, erection of the absorber building, and installation of its equipment, piping and electrical work, final checkout of the reagent preparation and gypsum dewatering buildings, startup, and tie-in outage.

### 6.7.5 Schedule Duration

As the schedule duration for the SCR/AHR portion of the Project is shorter than the FGD portion, the combined schedule shows a separate outage during Months 42-44 for an early tie-in of the SCR and Air Heater, should their operation be required prior to the FGD systems being placed into service; however, as there is no upgrade of the existing ID fan in the combined project, Unit 9 would have to be operated at reduced load until the FGD system is brought on-line.

If the SCR is not required before Month 50, the SCR/ARH tie-in outage can be slipped to occur concurrently with the FGD system tie-in.

#### 6.7.6 Assumptions and Clarifications

It is assumed that craft requirements and lay down areas required by the increase in materials and equipment for the combined project can be accommodated.

The fan modifications included in the costs for the Stand-Alone SCR project have been deleted in the combined project and replaced with larger ID Fans.