NO_X Mitigation Measures

Selective Catalytic Reduction for Combustion Turbines

Technical Support Document

New Source Performance Standards Review for Stationary Combustion Turbines

Docket ID No. EPA-HQ-OAR-2024-0419

U.S. Environmental Protection Agency

Office of Air and Radiation

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1. Introduction

This document describes the EPA's approach to estimating the costs of selective catalytic reduction (SCR) systems to reduce nitrogen oxide (NO_X) emissions from combustion turbines. The primary source of this information for SCR capital and variable operating costs on new and reconstructed combustion turbines is the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) Flexible Generation report.[1] The primary source of information on the fixed operating costs for SCR is the Integrated Planning Model (IPM).[2]

SCR involves injecting a nitrogen-based reducing agent, also known as a reagent, into the post-combustion flue gas from a combustion turbine. Then, if the flue gas is within a specific temperature range and in the presence of a catalyst, the reagent will react with the NO_X in the flue gas to reduce NO_X into molecular nitrogen and water vapor. Adding SCR to an EGU reduces emissions of NO_X, but results in emissions of ammonia and the required auxiliary load and backpressure decrease the efficiency of the combustion turbine.

[1] "Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generation Units for Flexible Operation." DOE/NETL-2023/3855. May 5, 2023.
[2] "IPM Model – Updates to Cost and Performance for APC Technologies: SCR Cost Development Methodology." January 2017. https://www.epa.gov/system/files/documents/2021-09/attachment_5-3_scr_cost_development_methodology.pdf

2. Cost of Selective Catalytic Reduction

The SCR costing information in the EPA's Cost Control Manual and the EPA documentation for the Integrated Planning Model include information for fossil fuel-fired boilers, but not for combustion turbines. The EPA's good neighbor plan included example cost calculations for SCR retrofits for model simple and combined cycle turbines but did not include the detailed costing equations behind those examples.[3] The EPA also reviewed multiple permits for combustion turbines that have recently commenced construction. However, the majority of recent permits do not have an SCR costing analysis so could not be used to develop costs based on vendor quotes. The EPA provides these various SCR costs for reference.

There are three main types of costs associated with an SCR system: capital costs, fixed costs, and variable costs. Capital costs include the SCR equipment costs and the cost of construction. The fixed costs include operation and maintenance costs that are independent of how often the SCR equipment is operated as well as property taxes and insurance.[4] Variable costs include ammonia requirements, catalysts costs, electricity required to operate the SCR, and reduced generation losses due to additional backpressure created from the SCR catalyst.

2.1. Data Sources

For the 40 CFR part 60, subpart KKKKa BSER analysis for NO_X, the EPA estimated the capital and operating costs of SCR using the NETL report titled *Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation* (DOE/NETL – 2023/3855, May 5, 2023). This report provides detailed costing for natural gas-fired simple cycle and combined cycle combustion turbines, all of which have SCR, but none have carbon capture. However, since the SCR system is installed prior to any carbon capture equipment, the incremental SCR costs are also applicable to combined cycle turbines with SCR. The simple cycle turbine costs were modeled using high temperature SCR and the combined cycle costs were modeled using conventional SCR.

The NETL report includes detailed costing tables that break capital costs out for specific pieces of equipment and was used as the primary source of information for the capital costs.

- The EPA summed the "Selective Catalytic Reduction System" costs to estimate the total plant costs (TPC) of the SCR system.
- The NETL reports do not include costs for the continuous emissions monitoring system (CEMS) and the EPA estimated the cost of a NO_X CEMS as $250,000 and included the NO_X CEMS costs in the TPC.
- The TPC were escalated to total overnight costs (TOC) using the same factor for the overall combustion turbine costs in the NETL report.[5]
- The costs for the initial catalyst fill were estimated using the volumes and costs in the NETL report and were included in the overall TOC costs.

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[3] See EPA-HQ-OAR-2021-0668

[4] When estimating social costs, taxes are not included since they are considered transfers rather than costs.

[5] The EPA divided the TOC given by the report by the TPC to calculate a factor to escalate TPC to TOC for each model plant combustion turbine.

- The TOC were escalated to total as spent capital costs using the same escalation factor used in the NETL report to escalate the overall combustion turbine costs.

The capital costs were annualized assuming a 7% interest rate and a service life of 15 years. The capital costs in the NETL Baseline Report with carbon capture is based on different generation of combustion turbines with higher efficiency and higher NO_X rates entering the SCR. However, the capital costs of the SCR were the same in both reports, and the EPA used the same capital costs regardless of the type of combustion controls used on the combustion turbine engine.

The NETL report does not include information to estimate the fixed costs of an SCR system. The EPA instead used the equations in the IPM costing analysis for natural gas-fired boilers to estimate the annual fixed costs.[6] The EPA estimated an annual cost of $10,000 to maintain the NO_X CEMS.

The NETL report includes detailed operating costs that were used to estimate variable operating costs.

- The primary operating cost is the ammonia reagent. The EPA estimated the cost of ammonia using the costs provided in the NETL report and determined the amount of ammonia needed for each turbine type by assuming that 0.57 tons of ammonia is required to control 1 ton of NO_X.[7,8,9] Ammonia slip is excess unreacted ammonia that passes through the SCR reactor. Ammonia slip increases as the catalyst activity decreases, but properly designed SCR systems, which operate close to the theoretical stoichiometry and supply adequate catalyst volume, maintain low ammonia slip levels, approximately 2 to 5 ppm.[10,11] The EPA estimated annual ammonia emissions assuming an average ammonia slip of 3.5 ppm.[12]
- The EPA used the auxiliary load required by the SCR that was directly provided in the NETL report. The EPA estimated the loss in output from operation of the SCR due to backpressure as 0.3% of the gross output. The overall result is a reduction in efficiency of 0.30%. The EPA estimated the price of electricity by determining the levelized cost of electricity (LCOE) of the specific plant at the assumed capacity factor for the specific

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[6] Absent combustion turbine specific cost models a natural gas-fired boiler is the closest approximation of exhaust gases from a combustion turbine.
[7] The 0.57 ratio assumes that each molecule of ammonia (NH_3) reaction with a molecule of NO.
[8] U.S. EPA. *EGU NO_X Mitigation Strategies Final Rule TSD.* Page 3. Accessed at: https://www.epa.gov/sites/default/files/2017-05/documents/egu_nox_mitigation_strategies_final_rule_tsd.pdf
[9] Muzio, Larry; Bogseth, Sean; and Vitse, Frederic. "*Emissions Control: Ammonia oxidation in simple-cycle SCRs can cause understatement of catalyst activity*." Combined Cycle Journal Online. Accessed at: https://www.ccj-online.com/emissions-control-ammonia-oxidation-in-simple-cycle-scrs-can-cause-understatement-of-catalyst-activity/
[10] U.S. EPA. *EPA Air Pollution Cost Control Manual; Section 4 (NO_X Controls); Section 4.2 (NO_X Post-Combustion); Chapter 2 (Selective Catalytic Reduction)*. Page 2-13. Accessed at: https://www.epa.gov/sites/default/files/2020-07/documents/cs4-2ch2.pdf
[11] U.S. EPA. *EPA Air Pollution Control Cost Manual; Section 4 (NO_X Controls); Chapter 2 (Selective Catalytic Reduction)*. Page 66/107. Accessed at: https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf
https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf
[12] The NETL report listed the permitting ammonia slip as 10 ppm.

analysis. The EPA estimated the increase in CO_2 emissions by multiplying the reduction in output by the emissions rate of the model plant.

- The EPA calculated the catalyst costs and the catalyst disposal costs from the NETL report by multiplying those values by the combustion turbine's capacity.

The cost effectiveness of SCR was determined by dividing the total annual costs by the annual NO_X reductions.

Model Plant	NETL SC1A	NETL SC2A*	NETL CC1A-F	NETL CC1A-H	NETL CC2A-F	NETL CC2A-H
Heat Input (MMBtu/h)	1,001	486	2,382	3,436	4,763	6,872
Net Output (MW)	114	51	369	552	738	1,107
Combustion Control Emissions Rate (lb/MMBtu) [ppm]	0.092 [25]	0.092 [25]	0.055 [15]	0.055 [15]	0.055 [15]	0.055 [15]
Post SCR Emissions Rate (lb/MMBtu) [ppm]	0.011 [3.0]	0.011 [3.0]	0.0066 [1.8]	0.0066 [1.8]	0.0066 [1.8]	0.0066 [1.8]
Capacity Factor (%)	40%	40%	40%	40%	40%	40%
SCR Capital Costs						
Bare Erected Costs	$2,047,000	$1,750,000	$1,798,000	$2,247,000	$2,923,000	$3,645,000
Total Plant Costs (including NO_X CEMS)	$3,075,000	$2,540,000	$2,732,000	$3,350,000	$4,284,000	$5,280,000
Total Overnight Costs (w/ SCR catalyst)	$4,001,000	$3,270,000	$3,857,000	$4,797,000	$6,275,000	$7,865,000
Total As Spent Capital	$4,371,000	$3,407,000	$4,213,000	$5,240,000	$6,855,000	$8,592,000
Annual Fixed Costs	$141,963	$126,609	$134,187	$150,197	$174,193	$199,818
Annual Operating Costs	$149,098	$76,566	$623,803	$872,223	$1,192,397	$1,671,329
Annual NO_X Reduction (tons)	71	35	305	440	610	880
Cost Effectiveness ($/ton NO_X)	$10,831	$16,698	$4,004	$3,632	$3,476	$3,199
Annual Ammonia Emissions (tons)	4.2	2.0	30.0	43.3	60.1	86.7
Annual Increase in CO_2 Emissions (tons)	321	155	2,277	3,281	4,554	6,563

Figure 1. SCR Costs for NETL Model Plants

* The EPA estimated the costs of a single turbine by dividing the NETL SCR costs in half.

2.2. SCR Cost Curves

2.2.1. Large EGU Turbines

The EPA plotted the as spent capital (as seen in Figure 2) and fixed costs (as seen in Figure 3) for the four example combined cycle turbines against their respective heat inputs to derive linear fits. These curves were used to estimate capital costs for other combined cycle units of varying sizes.

To estimate the capital costs of SCR for simple cycle turbines, the EPA compared the estimated costs using the equations derived for the combined cycle turbines to the previously calculated values for the LMS1000 turbine to establish a ratio between the two. This factor (1.5) was then applied to the combined cycle cost curve to estimate the SCR capital costs for simple cycle turbines of various sizes.[13]

The EPA estimated the fixed costs of SCR for simple cycle turbines using the fixed cost line derived from the model simple cycle turbines.

[13] The estimated capital costs on a MMBtu/h basis of hot SCR for simple cycle turbines is 50 percent higher than the cost of conventional SCR for combined cycle and combined heat and power facilities. The estimated capital cost for utility size combined cycle turbines is approximately $10/kW and the estimated capital costs for utility size simple cycle turbines approximately $50/kW.

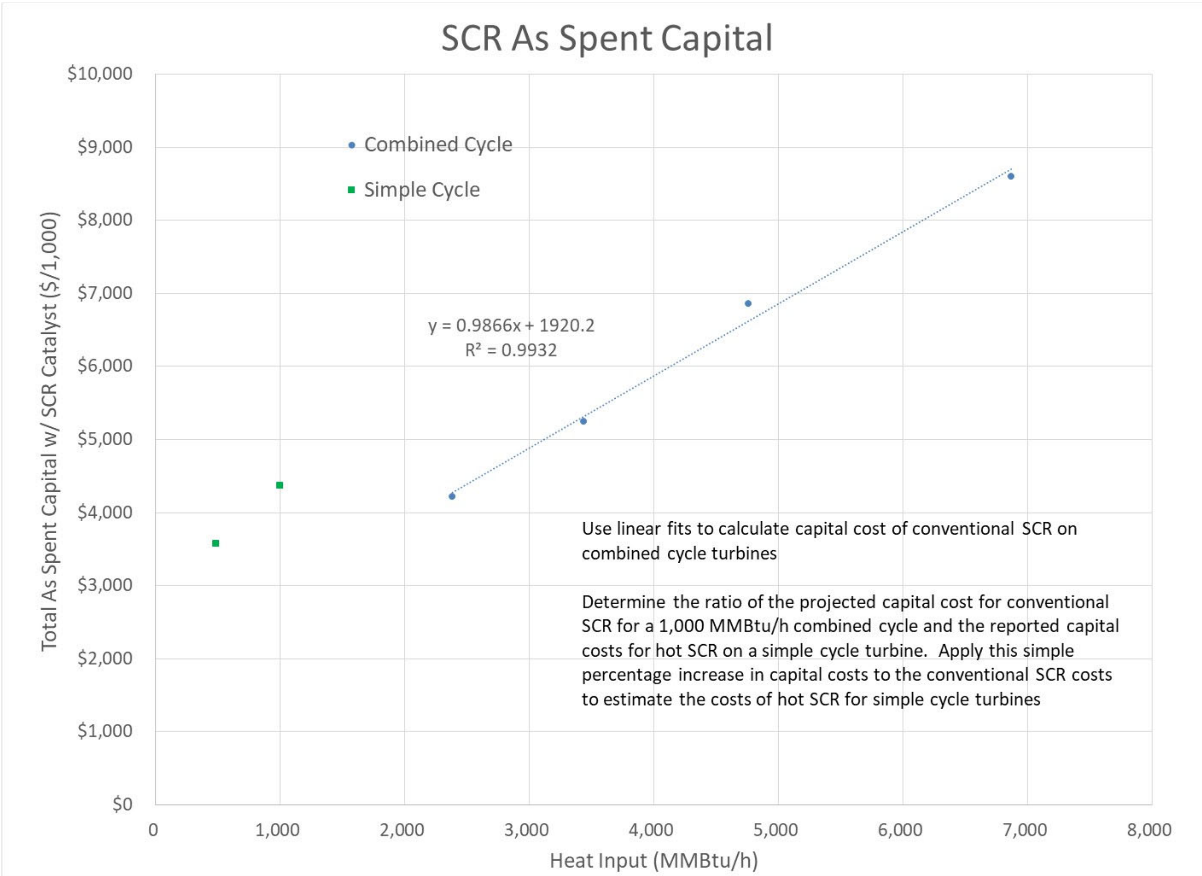

Figure 2. SCR As Spent Capital Costs vs. Heat Input

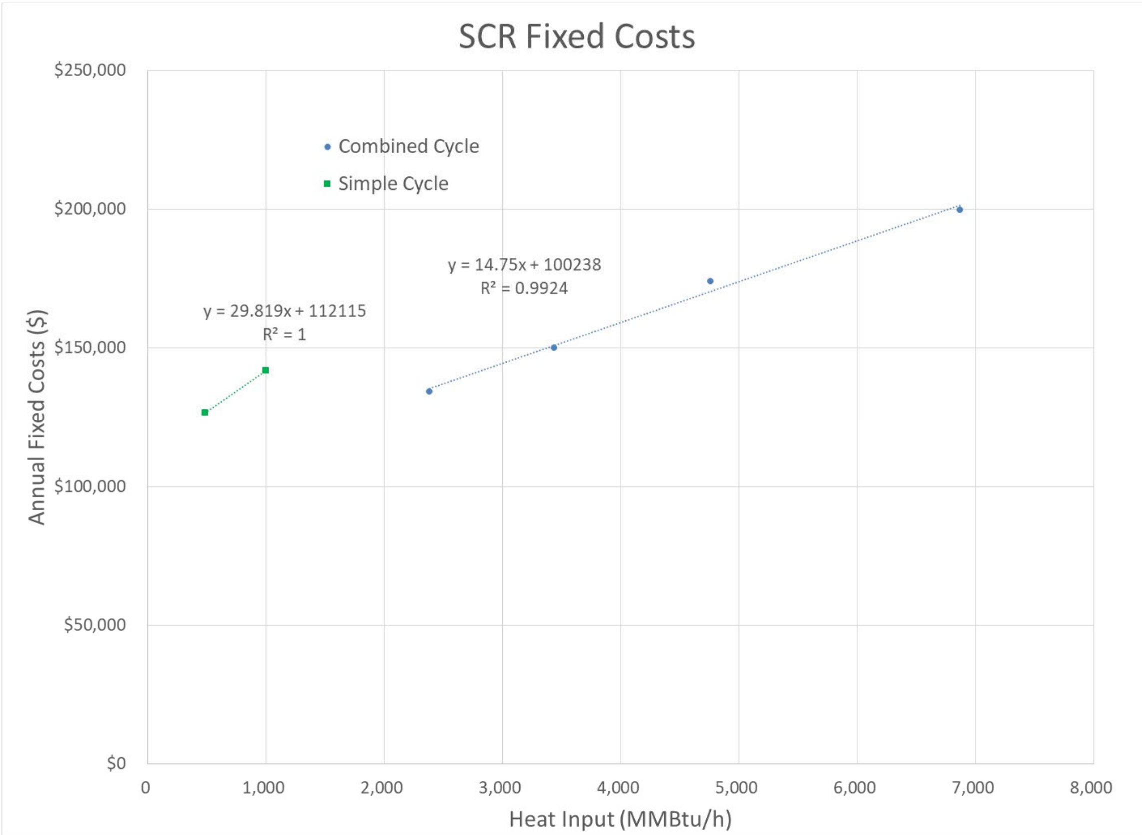

Figure 3. SCR Fixed Costs vs. Heat Input

The EPA estimated variable operating costs, that are primarily impacted by the ammonia requirements and included reduced electricity sales because operating an SCR reduces the efficiency of an EGU which affects its ability to generate electricity and impacts the control technology's cost effectiveness because electricity sales are one component in the overall accounting of the project.

The variable operating costs were determined for combined cycle turbines operating at a 60% capacity factor and for simple cycle turbines operating at a 20% capacity factor at different NO_X reduction rates (as seen Figure *4*). These costs were used to determine the variable operating costs at different reduction rates but static capacity factors. While variable operating costs increase with lower NO_X reduction rates because the efficiency loss is constant regardless of the reduction rate (variable costs may vary due to the different value of the lost electric sales). Costs were calculated using the curve fits in Figure 4.

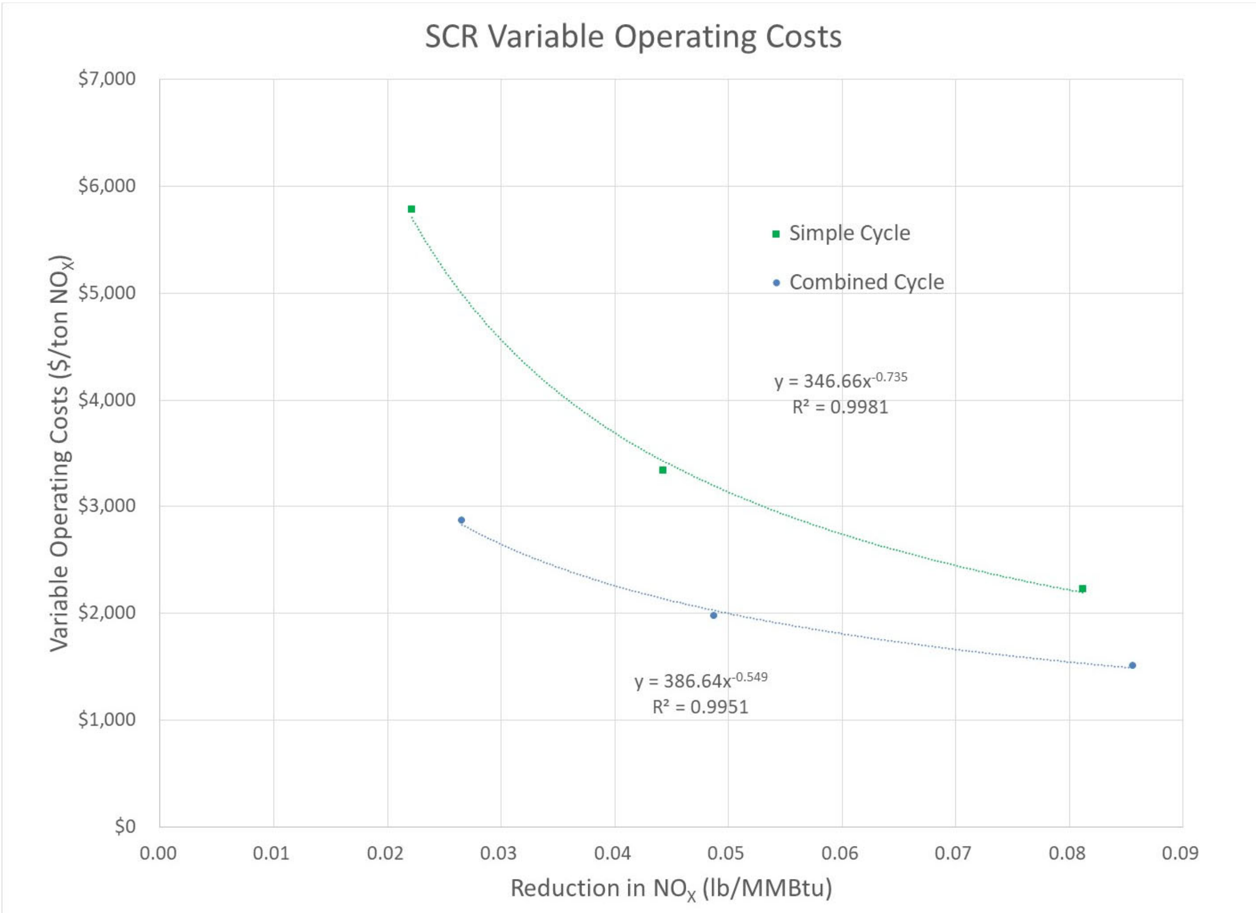

Figure 4. Variable Operating Costs vs. Reduction in NOx (lb/MMBtu)

2.3. <u>Compliance Costs</u>

The EPA used the derived equations and the estimated NO_X reductions to develop curves that demonstrated compliance costs at varying 12-operating month capacity factors for combustion turbines of various sizes—including small EGUs and combustion turbines located at compressor stations. The following figures show estimated control costs assuming the combustion turbines reduced NO_X emissions from the current subpart KKKK standards to the proposed short term high load emissions standard of 3 ppm NO_X. These curves represent the costs using representative long term NO_X emission rates. Based on review of NO_X emissions reported to the EPA, combustion turbines with guarantees of 25 ppm NO_X emit on average 20 ppm NO_X, combustion turbines with guarantees of 15 ppm NO_X emit on average 14 ppm NO_X, combustion turbines with guarantees of 9 ppm NO_X emit on average 7 ppm NO_X, and combustion turbines with SCR complying with a short-term rate of 3 ppm NO_X emit on average 2 ppm NO_X.

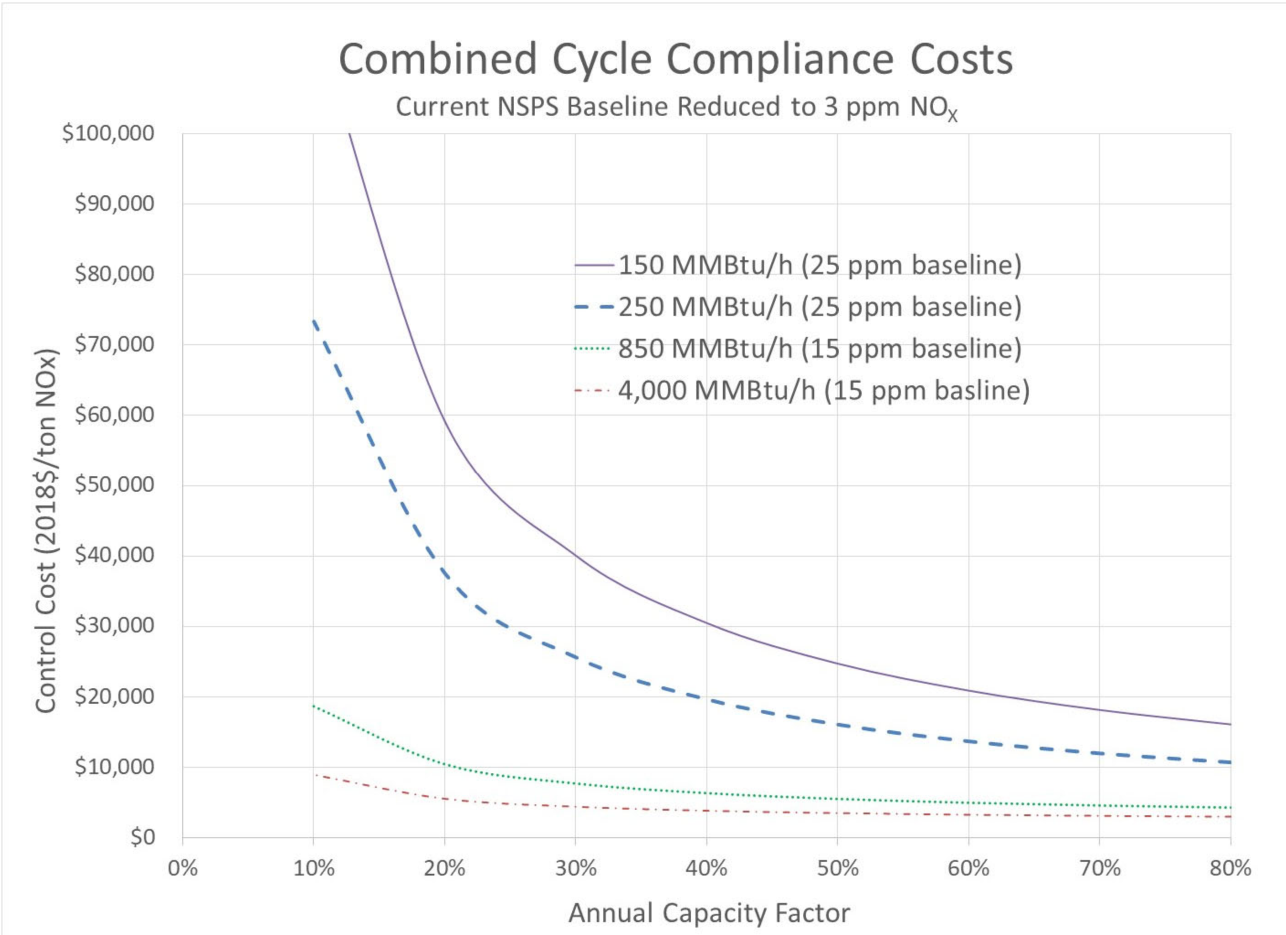

Figure 5. Combined Cycle Compliance Costs

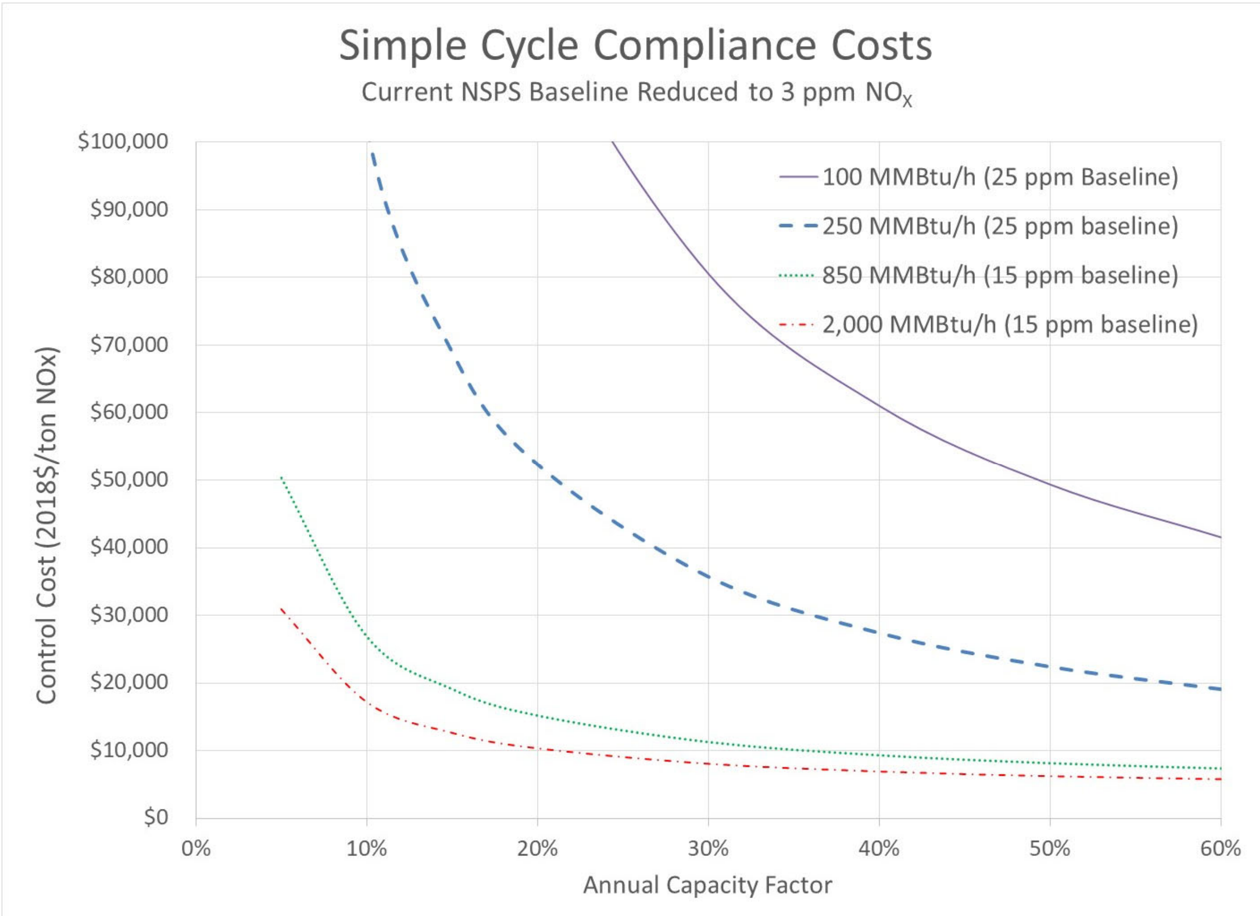

Figure 6. Simple Cycle Compliance Costs

3. Converting from ppm NO_X to lb NO_X/MMBtu

The NO_X emission rates provided in the NETL flexible generation report were separately provided in both a pound per MMBtu basis and a ppm basis. The emission rates used by the EPA are provided in the table below (Figure *7*):

Emissions Rate (ppm)	Emissions Rate (lb/MMBtu)
25	0.0923
15	0.0554
9	0.0332
5	0.0185
3	0.0111
2	0.0074

Figure 7. NOx Emission Rate Conversions

For a natural gas-fired combustion turbine NO_X emission rate, the EPA used a conversion factor of 271 to convert from ppm to lb/MMBtu. For a combustion turbine that combusts fuel oil, the EPA used a conversion factor of 257. In this case, a NO_X rate of 42 ppm would equal 0.16 lb/MMBtu.

4. Comparison With Other Costing Information

The SCR costing information in the EPA's Cost Control Manual and the EPA documentation for the Integrated Planning Model include information for fossil fuel-fired boilers, but not for combustion turbines. The EPA's good neighbor plan included example cost calculations for SCR retrofits for model simple and combined cycle turbines but did not include the detailed costing equations behind those examples.[14] The EPA also reviewed multiple permits for combustion turbines that have recently commenced construction. However, the majority of recent permits do not include a SCR costing analysis so could not be used to develop costs based on vendor quotes. The EPA provides these various SCR costs for comparison purposes.

4.1. Permits Statements of Basis

4.1.1. Summary of Permits

The EPA found 2 recent permits that included detailed costing information for hot SCR—Jack County Generation Facility and Nelson Energy Center. Both permits did a BACT cost analysis of SCR for simple cycle stationary combustion engines. The BACT analysis for the Jack County Generation Facility goes into much more depth than the BACT analysis for the Nelson Energy Center. The Nelson Energy Center BACT analysis does not itemize any costs. It also does not state whether the final cost is quoted or estimated from EPA's Air Pollution Cost Control Manual (APCCM). What follows in *section 4.1.1* is solely a summary of the costs and methodologies that the authors used in their respective permits.

The BACT analysis for Jack County Generation Facility considered an existing installation of three Siemens V84.3a combustion turbines. The capacity and heat rate for these combustion turbines are 180.2 MW and 10,261 Btu/kWh, respectively. The permit author's estimated controlled (w/ SCR) and uncontrolled (w/ DLN) NO_X emission rates for a single turbine are 5 and 14 ppmvd (15 percent O_2), respectively, based on the manufacturer's exhaust analysis. This gives an estimated 9 ppmvd (15 percent O_2) difference between the controlled and uncontrolled scenarios. The assumed annual hours of operation is 2500, giving an annual capacity factor of 29 percent. Using the difference of estimated NO_X emission rates and hours of operation, the permit authors calculated a NO_X emissions reduction of 79.2 tpy.

The estimated SCR capital costs includes a total of three SCRs (one for each turbine), quoted by Mitsubishi at $18.1 MM. Using section 1, chapter 2 (boiler costs) and section 4, chapter 2 (SCR boiler costs) of the APCCM, the permit authors estimated a total capital investment of $32.1 MM. The total capital investment includes all direct and indirect capital costs such as instrumentation, construction costs, freight, sales tax, startup costs, and contractor costs. Note that the APCCM is in 2016 dollars and specifically for boilers, i.e., the multipliers may not apply to current SCRs installed on simple cycle turbines.

The permit authors estimated the SCR annual costs using a combination of vendor quotes and the APCCM. They estimate annual costs for the reagent (ammonium), parasitic load (electricity), and catalyst to be $0.03 MM, $0.25 MM, and $0.66 MM, respectively. The maintenance cost

[14] See EPA-HQ-OAR-2021-0668

($0.16 MM), labor cost ($0.10 MM), and insurance/admin costs ($0.94 MM) were estimated by the permit authors based on a percentage of the total capital investment, per the APCCM. Finally, the permit authors estimated the capital recovery cost ($3.14 MM) based on a 25-year life and 8.5 percent prime rate, giving a total annualized cost (TAC) of $5.3 MM. They divided the TAC by the emissions reduction, giving an annual cost effectiveness of $67,088 per ton NO_X reduced.

As for the Nelson Energy Center, the BACT analysis was done for an existing installation of two GE Model 7FA.03 simple cycle turbines. The summer and winter capacities are 150 and 190 MW, respectively. Although the Nelson Energy Center permit asked for 2400 operating hrs (27 percent annual capacity factor), the authors report that the combustion turbines are unlikely to even operate for 1000 hrs given the averaged performance of their neighbors. Regardless, the authors chose to use a conservative 1275 operating hours (15 percent annual capacity factor) for their calculations. Combining the expected operating hours with controlled/uncontrolled estimated NO_X rates of 2.5/9 ppmvd (15 percent O_2), the authors calculated an annual NO_X emissions reduction of 93.1 tpy.

As for their SCR costs, the Nelson Energy Center BACT analysis reports a capital cost of over $8 MM and a cost-effectiveness of $58,420 per ton of NO_X removed.

Permitted Plant	Jack County Generation Facility	Nelson Energy Center
Heat Input per turbine (MMBtu/h)	1849	
Net Output per turbine (MW)	180	150 (summer), 190 (winter)
Capacity Factor (%)	29	15
Number Turbines	3	2
Combustion Control Emission Rate (ppmv)	14	9
Post SCR Emission Rate (ppmv)	5	2.5
Total Direct Costs ($MM)	21.5	
Total Indirect Costs ($MM)	6.45	
Total Capital Investment ($MM)	32.1	>8
Total Direct Annual Costs ($MM)	1.20	
Total Indirect Annual Costs ($MM)	4.11	
Total Annualized Costs ($MM)	5.31	
Annual NO_X Reduction (tons)	79.2	93.1
Cost Effectiveness ($/ton NO_X)	67,088	58,420

Figure 8. SCR Costs for Permitted Plants

4.1.2. Comparing Costs: Permits vs. EPA's NETL-based Analysis

A NETL-based analysis (see

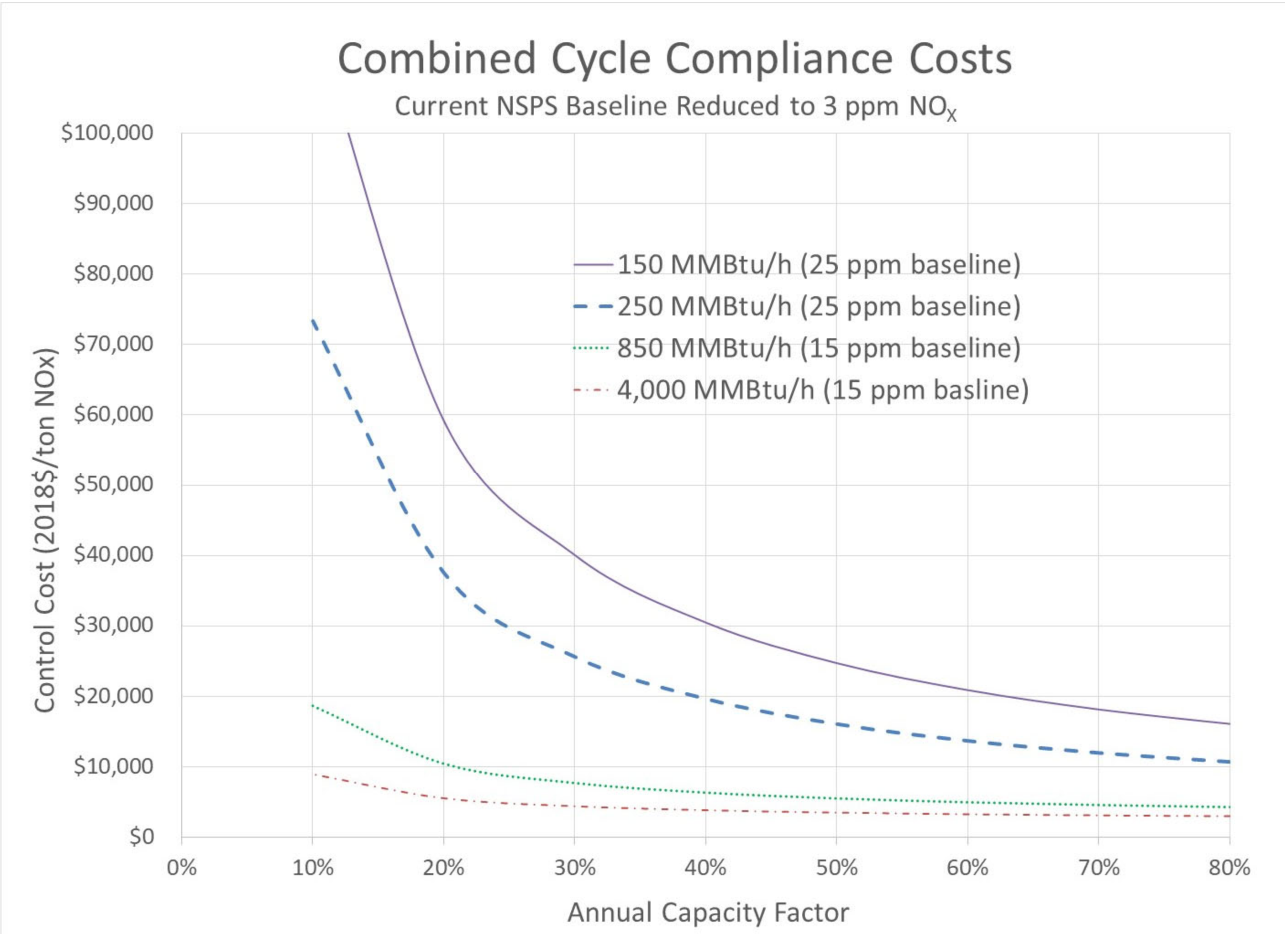

Figure 5) using the heat inputs and capacity factors of the Jack County Generation Facility and Nelson Energy Center turbines predicts that the cost effectiveness of SCR, in 2024 dollars, would range between \$12,000 - \$17,500 tons NO_X removed, as opposed to the \$67,088 and \$58,420 tons NO_X removed calculated by the corresponding BACT analyses (also 2024 dollars). To better understand the difference between the cost effectiveness predicted by the NETL-based analysis and that reported by the BACT analysis of the Jack County permit, a comparison of their detailed cost breakdowns was done. Again, note that the Nelson permit did not contain a detailed cost breakdown, and therefore, a detailed comparison between the Nelson permit's cost effectiveness and that of the other analyses was not possible. Also note that, for this comparison, the NETL costs were adjusted from 2018 dollars to 2024 dollars by applying a 1.25 CPI inflation factor.[15]

Most of the cost effectiveness difference between NETL and Jack County analyses stems from the large differences between the total capital investment of the NETL analysis (\$8.1 MM per combustion turbine) and that of the Jack County analysis (\$10.7 MM per turbine). This may be

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[15] https://www.in2013dollars.com/us/inflation/2018?amount=1

due to the multiplicative factors that the Jack County analysis used to estimate the total indirect costs (30%) and added contingency cost (15%). This difference carried through to the estimated annual capital costs and was compounded since the NETL-based analysis used a lower capital rate (10.98% vs 12.77%). The NETL-based analysis assumed an interest rate and service life of 7% and 15 years, respectively, whereas the Jack County permit assumed 8% interest over 25 years, and a 3% insurance and admin charge.

Lastly, the annual variable costs between the NETL-based and Jack County analyses differ by ~7.5x ($2,115 vs $15,214 per NO_X removed, respectively). Most of this seems to be due to the estimated cost of replacing the catalyst. Additionally, the EPA analysis assumes a 12 ppmv NO_X reduction against a reduction of 10 ppmv for the Jack Count analysis.

4.2. Good Neighbor Example Calculation

The example costs from the Sargent & Lundy LLC document titled "Combustion Turbine NOx Control Technology Memo" were used to estimate an SCR cost effectiveness of NO_X removal. These are high-level, order-of-magnitude cost estimates for an SCR retrofit of a simple cycle turbine.

The cost estimates only include project costs and annual operation & management (O&M) costs, The estimated project and O&M costs for a simple cycle SCR retrofit included all direct and indirect costs that were considered as part of the Jack County permit's total capital investment (TCI), including contingency, and direct annual costs (DAC), respectively. As such, a cost effectiveness based on the Sargent & Lundy estimates can be estimated using the relevant parameters in the Jack County permit (see Figure *9* footnotes). Note that the Sargent & Lundy estimates were adjusted from 2021 dollars to 2024 dollars.

Item Description	**Percentage**	**Cost (2024 $)**
Total Capital Investment (TCI)		$18,560,000
Insurance and Admin[a]	3%	$556,800
Capital Recovery[a]	9.77%	$1,813,312
Direct Annual Costs (DAC)		$81,200
Total Annual Costs (TAC)		$2,451,312
Emissions Reduction (tpy)[a,b]		$92
Cost Effectiveness ($ per ton reduced)		$30,951

Figure 9. Estimated SCR costs extracted from Sargent & Lundy LLC's Good Neighbor Example Calculations

[a] Borrowed from the Jack County permit BACT analysis.
[b] De facto assumes the same heat input, capacity, capacity factor, and emission rates as the Jack County combustion turbines.

The Sargent & Lundy heat input and capacity factor were not given, and so were assumed to be similar to those of the Jack County permit.

4.3. <u>IPM Natural Gas-Fired Boilers SCR Costs</u>

The EPA calculated SCR costs for natural gas-fired boilers using the EPA documentation for the Integrated Planning Model. The costs were calculated using the same output, efficiency, heat input, capacity factor, NO_X input to the SCR, and NO_X output from the SCR as the six model plants in Figure *10*. Overall cost effectiveness for natural gas-fired boilers are around 3 times higher than simple cycle plants and almost 6 times higher than combined cycle plants. Capital costs for natural gas-fired boilers are around 4 times higher than simple cycle plants and around 10 times higher than combined cycle plants. Annual fixed costs are higher for simple cycle plants and lower for combined cycle plants when compared to the boilers. Annual operating costs are higher for both simple and combined cycle plants. Figure *10* shows the full IPM costing analysis for natural gas-fired boilers.

Model Plant	NETL SC1A	NETL SC2A*	NETL CC1A-F	NETL CC1A-H	NETL CC2A-F	NETL CC2A-H
Heat Input (MMBtu/h)	1,001	486	2,382	3,436	4,763	6,872
Net Output (MW)	114	51	369	552	738	1,107
Combustion Control Emissions Rate (lb/MMBtu) [ppm]	0.092 [25]	0.092 [25]	0.055 [15]	0.055 [15]	0.055 [15]	0.055 [15]
Post SCR Emissions Rate (lb/MMBtu) [ppm]	0.011 [3.0]	0.011 [3.0]	0.0066 [1.8]	0.0066 [1.8]	0.0066 [1.8]	0.0066 [1.8]
Capacity Factor (%)	30%	30%	30%	30%	30%	30%
SCR Capital Costs						
Total Base Module Cost	$13,335,000	$7,990,000	$25,651,000	$34,503,000	$45,195,000	$61,546,000
Total Project Cost	$19,296,000	$11,560,000	$37,114,000	$49,922,000	$65,395,000	$89,053,000
Annual Fixed Costs	$132,000	$105,000	$143,000	$170,000	$199,000	$254,000
Annual Operating Costs	$120,000	$58,000	$283,000	$405,000	$566,000	$813,000
Annual NO_X Reduction (tons)	107	52	153	220	305	441
Cost Effectiveness ($/ton NO_X)	$28,185	$35,035	$37,497	$35,005	$33,127	$31,321
Annual Ammonia Emissions (tons)	6.3	3.1	15	22	30	43
Annual Increase in CO_2 Emissions (tons)	482	233	1,138	1,640	2,277	3,282

Figure 10. SCR Costs for IPM Natural Gas-Fired Boilers

5. Estimated Costs for Upgraded SCR and Improved Operation and Maintenance

Not all combustion turbines that have commenced construction within the last 5 years with SCR are currently operating at NO_X emission rates higher than the proposed NSPS emissions rate for combustion turbines with a BSER based on the use of SCR. The EPA estimated that if the required emissions reduction is greater than 0.0074 lb NO_X/MMBtu (2 ppm), the SCR would have to be upgraded beyond the base line level of control. If the required emissions reduction was less than 0.0074 lb NO_X/MMBtu, the EPA estimated that improved operation and maintenance practices could be used to increase the reduction achieved by the SCR such that these units would be operating at the proposed NSPS emissions rate.

The incremental capital costs of installing an SCR with increased reductions (upgraded SCR) were estimated as 10 percent of the equipment costs and one third of the catalyst costs of the NETL model plants. The incremental increase in fixed costs were estimated as 10 percent of the maintenance and material costs and tax and insurance costs of the NETL model plants. For SCR upgrade incremental variable costs, the EPA used the same ammonia and catalyst \$/ton NO_X reduced, and one third of the backpressure costs as the NETL model plants.

For the improved operation and maintenance case, the EPA estimated the incremental increase in variable costs using the same ammonia and catalyst \$/ton NO_X of the NETL model plants. The EPA did not include any additional capital or fixed costs when estimating the costs of these reductions.

Figures 12 through 15 show the curves used for estimating the costs of installing SCR with greater levels of NO_X reduction, relative to the base case.

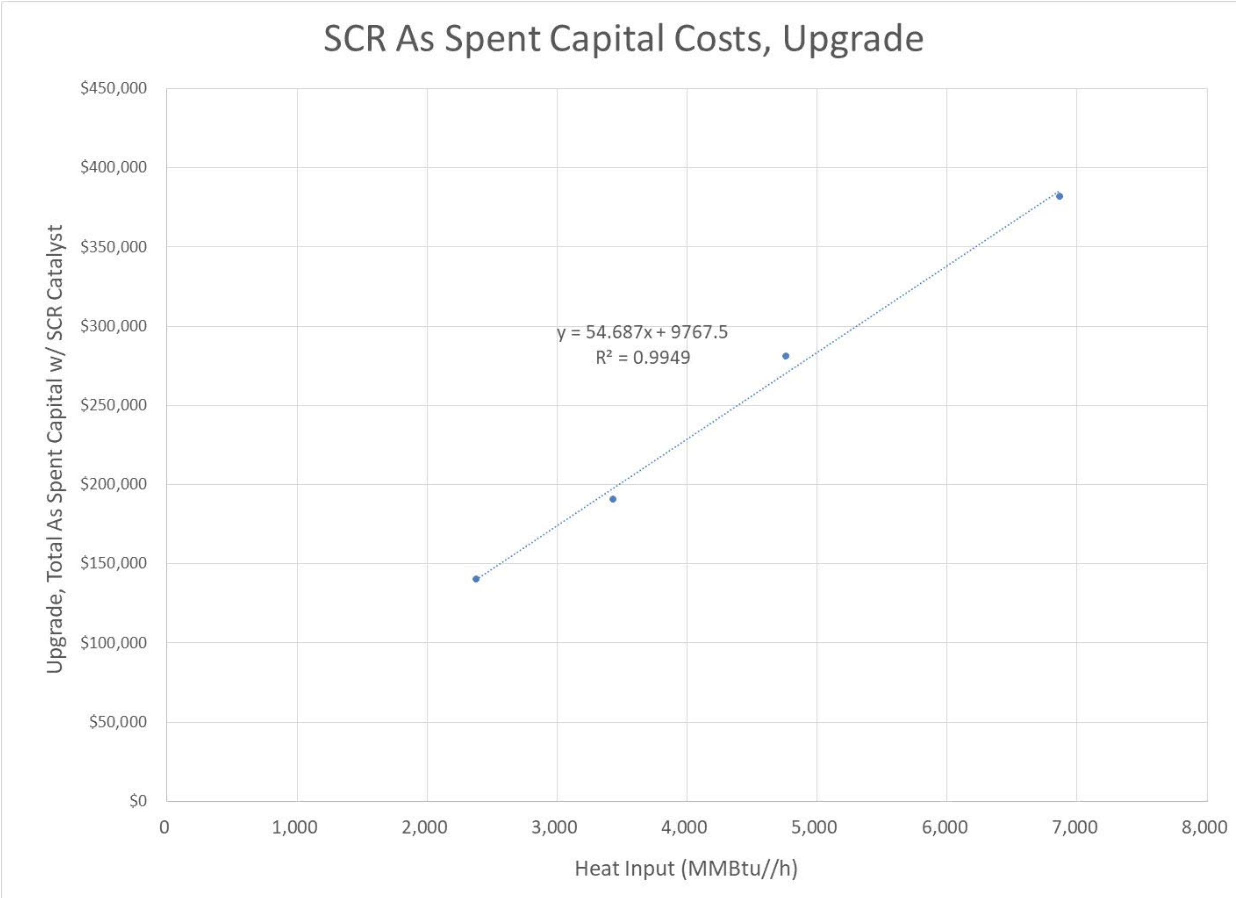

Figure 12. SCR Upgrade Incremental As Spent Capital Costs vs. Base Load Rating (MMBtu/h)

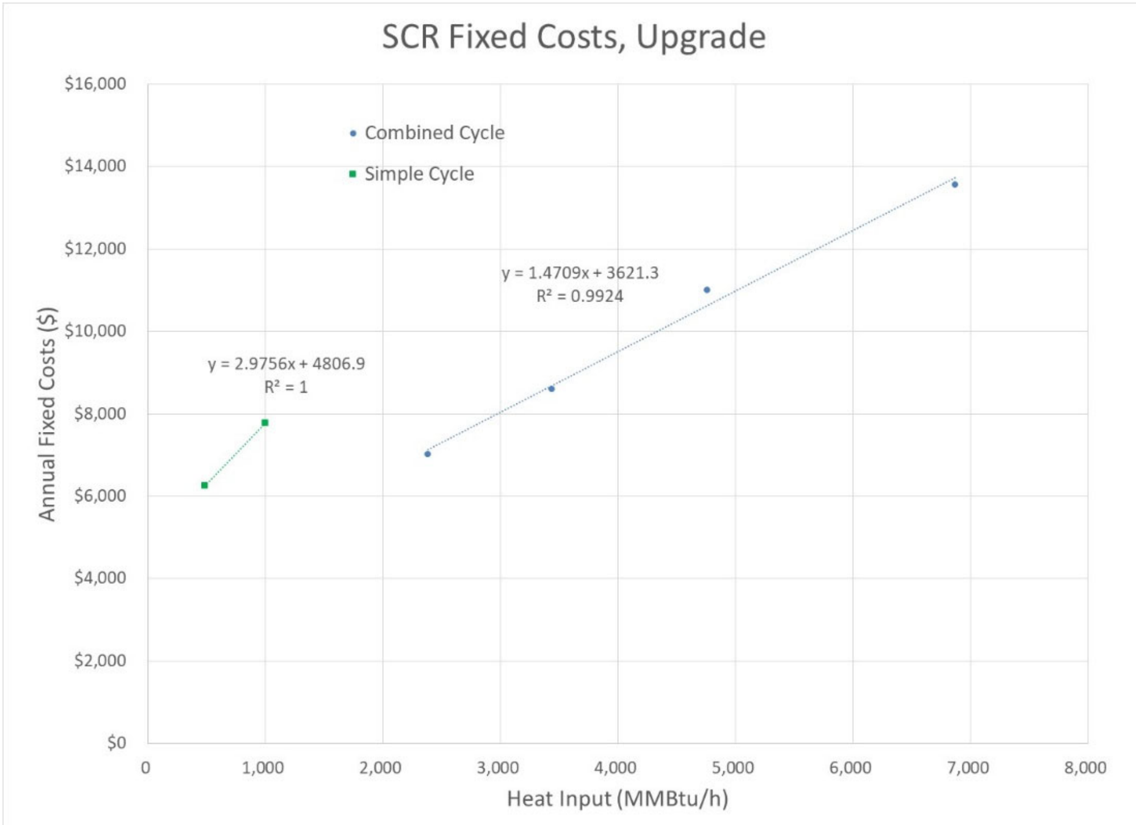

Figure 13. SCR Upgrade Incremental Fixed Operating Costs vs. Base Load Rating (MMBtu/h)

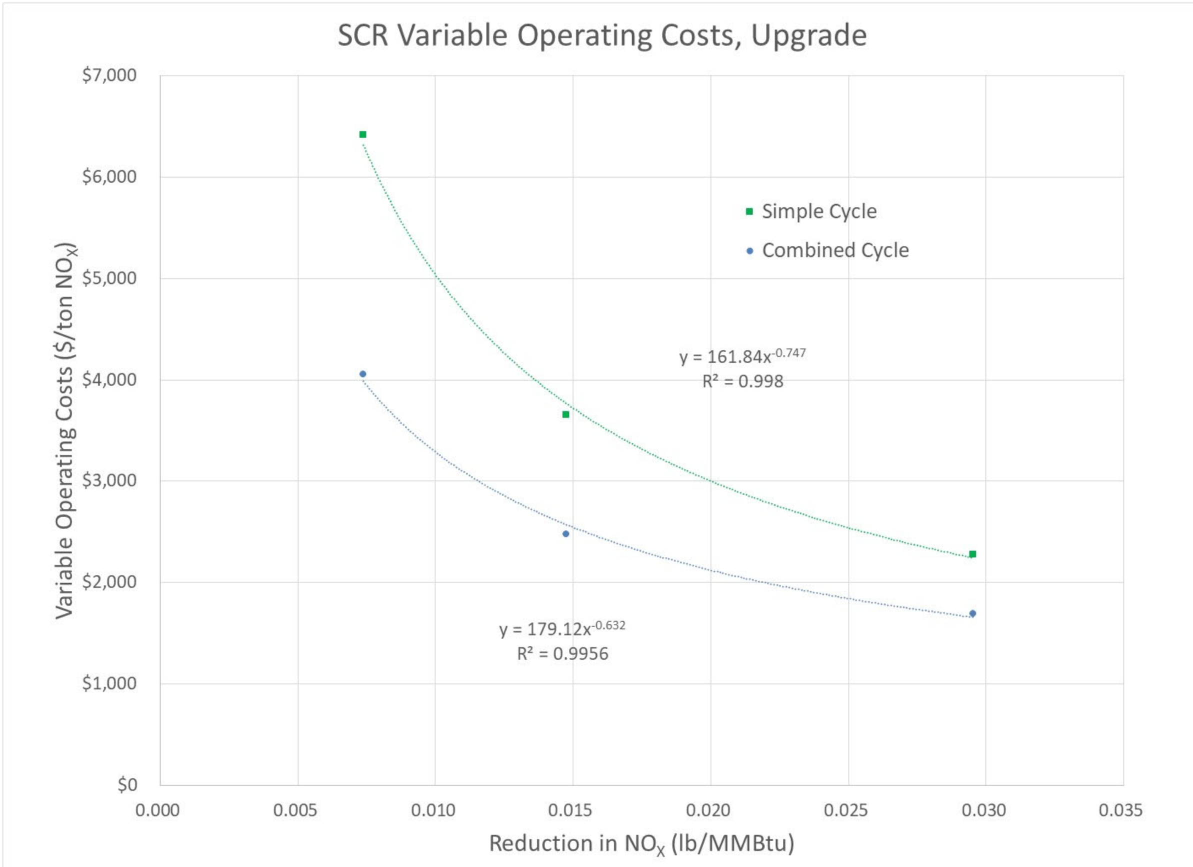

Figure 111. SCR Upgrade Incremental Variable Operating Costs vs. Reduction in NOx (lb/MMBtu)

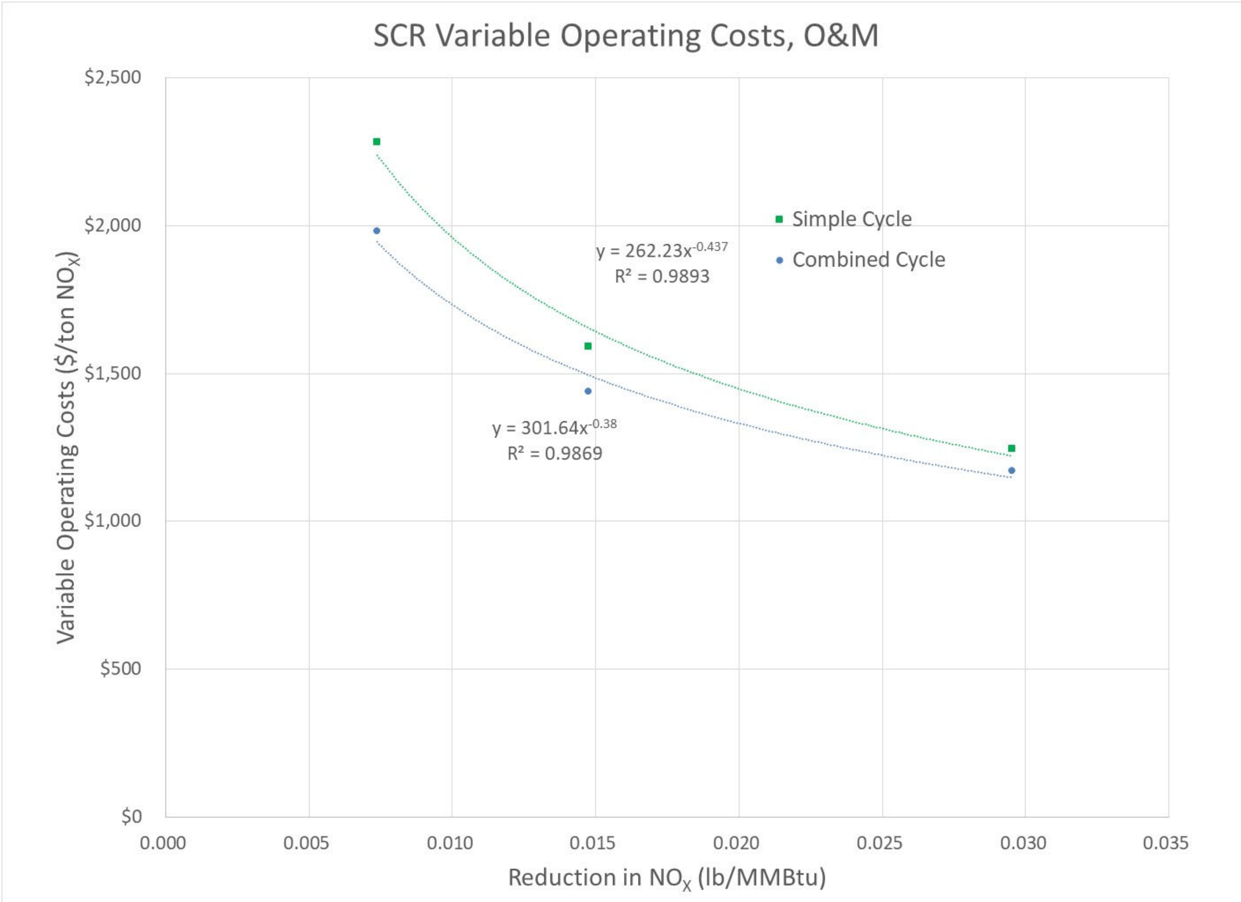

Figure 15. SCR Improved Operation and Maintenance Incremental Variable Operating Costs vs. Reduction in NOx (lb/MMBtu)