CAPITAL COST AND COST-EFFECTIVENESS OF ELECTRIC UTILITY COAL-FIRED POWER PLANT EMISSIONS CONTROL TECHNOLOGIES: 2017 UPDATE

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Prepared for
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December 2017

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SECTION 1

OVERVIEW AND SUMMARY

The utility industry is approaching the end of a third consecutive decade characterized by widespread retrofits of flue gas emission controls to coal-fired power plants. These actions are in response to several federal and state mandates, most notably the Cross State Air Pollution Rule (CSAPR), which required retrofit of flue gas desulfurization (FGD) and selective catalytic reduction (SCR) at many units by 2015. In a parallel effort, environmental controls were retrofit to satisfy the Mercury and Air Toxics Standards (MATS), for which the earliest compliance date was also in 2015. Further, FGD and SCR have been required to address EPA's visibility rules, including regional haze and Best Available Retrofit Technology (BART) requirements, as well as the increasingly stringent National Ambient Air Quality Standards (NAAQS). Finally, individual utility company Settlement Agreements with the Environmental Protection Agency (EPA) and the Department of Justice (DOJ) over alleged New Source Review (NSR) violations influenced equipment installation for some owners.

Robust demand for environmental control equipment was experienced from 2006 through 2009, straining international and domestic supply chains. Demand for this equipment has since relaxed. As a result, the availability and price of key process components and non-ferrous (i.e., corrosion-resistant) metals have changed – to the benefit of the purchaser. Hourly labor rates for skilled construction labor continue to increase, however.

This report shows the escalation of capital cost to retrofit FGD has somewhat abated, while cost continues to climb to retrofit SCR. For wet FGD retrofit to a typical plant, the average capital cost for a 500 MW unit in the 2012-2016 time frame is approximately $450/kW, relatively unchanged from the 2008-2011 time frame. The average capital cost for dry FGD is about the same at $450/kW, but this cost includes a fabric filter to control particulate matter. For SCR, capital cost continues to escalate. A 500 MW unit incurred an average capital cost of about $325/kW to retrofit with SCR in the 2012-2016 time frame, representing a significant increase from the $275/kW observed in the 2008-2011 time frame.

Similar to FGD and SCR process equipment, the capital cost to retrofit fabric filters varies widely as affected by site conditions and the year of installation. The most recent group of fabric filters, installed to support meeting MATS mandates, exhibit the highest cost. For this group the average cost to retrofit a fabric filter to a 500 MW unit is approximately $325/kW.

A contributing reason for the continued escalating cost for fabric filter and SCR process equipment is the ever-increasing complexity of the host sites. The remaining units that are candidates for retrofit are typically located at older and more crowded plant sites, offering less space to locate equipment and for construction. Such retrofits typically require convoluted and complex ductwork, increasing installation difficulty.

This report also addresses FGD and SCR operating cost. The levelized cost of SO_2 removal is determined from capital and operating cost, and reported as the cost to remove one ton of SO_2. At $450/kW, a wet FGD process retrofit to a 500 MW unit firing coal with sulfur content of 5 lbs/SO_2/MBtu, and incurring typical operating costs, will expend near $600 to remove each ton of SO_2. For a coal with this sulfur content, each increase in wet FGD capital cost by $100/kW elevates the cost of SO_2 removal by almost $100 per ton. For PRB coal with a sulfur content of 0.9 lb SO_2/MBtu, a $450/kW wet FGD process retrofit to a 500 MW plant will expend $2,600/ton for SO_2 removal. For this PRB coal, each $100/kW increase in FGD capital cost will increase SO_2 removal cost by $450/ton.

The cost for SCR consumables that drive operating cost – catalyst and reagent – continue to evolve. Catalyst unit price has remained low in the last 4-5 years, with new catalyst requiring typically less than $5,000/cubic meter. The cost of ammonia-based reagent appears to have "decoupled" from the historical relationship with natural gas, due to strong fertilizer demand. Typical delivered cost for anhydrous ammonia is $600-800/ton and these prices are expected to persist into the indefinite future. For many SCR applications, reagent has replaced catalyst supply as the largest SCR operating cost component.

The levelized cost for NO_x control is determined from capital and operating cost, and reported as the cost to remove one ton of NO_x. For a typical 500 MW unit firing an eastern bituminous coal, and equipped with a boiler generating 0.38 lb/MBtu of NO_x, an SCR process requiring $325/kW provides NO_x removal for about $4,600/ton. For this same unit, each $100/kW increase in SCR capital cost elevates NO_x removal cost by about $1,000/ton. For a 500 MW unit firing PRB and producing NO_x at a rate of 0.20 lb/MBtu, an SCR process requiring $325/kW provides NO_x removal for about $8,600/ton. Each $100/kW increase in SCR capital cost incurred for this unit increases NO_x removal cost effectiveness by $2,200/ton.

The rate of cost escalation to retrofit FGD has abated, but for SCR cost continues to increase. The cost increases for SCR are driven by the elevated complexity of smaller sites, which generally host older units. For both FGD and SCR, incurred capital cost varies significantly around the mean values cited in this summary, and a case-by-case evaluation should be conducted.

The escalation in cost for these controls since 2000 challenges the economic viability of units adopting such technology in the face of eroding wholesale power prices. For wet FGD applied to a 500 MW unit firing either eastern bituminous or PRB coal, the total cost of owning and operations – that is, the cost of capital recovery and all fixed and variable operating costs – can equate to half of the lowest wholesale power price ($22.5/MWh) observed in 2016. The total cost for owning and operating SCR is more than ¼ of this lowest wholesale energy price. Retrofitting both FGD and SCR processes can incur a total cost equal to the fuel cost for a coal-fired steam boiler (at $1.50/MBtu and heat rate of 10,000 Btu/kWh) and approach the fuel cost for natural gas-fired combined cycle generating unit (at $3/MBtu and a heat rate of 7,000 Btu/kWh). The imposition of such controls significantly affects the competitiveness of the unit in wholesale power markets.

SECTION 2

BACKGROUND

2.1 INTRODUCTION

The capital cost to retrofit flue gas emission controls to coal-fired power stations escalated significantly over the ten-year period starting from the year 2000.

Several factors drive the escalated costs. Although prices for specialized materials of construction have subsided, the cost for specialized labor continues to escalate. Perhaps more important, the sites remaining in the inventory of units to be retrofit are more challenging – these sites are more complex and limit access for construction personnel and equipment.

2.2 ENVIRONMENTAL MANDATES

Several major environmental control regulations have been issued in recent years, all requiring compliance within a short time period.

Most notably, the Cross State Air Pollution Rule (CSAPR) required retrofit of FGD and SCR to many units by not later than 2015 to lower the permissible level of SO_2 and NO_x emissions.[1] Environmental controls have also been retrofit since about 2012 to satisfy the Mercury and Air Toxics Standards (MATS) rule, and it is conceivable that additional control technology will be retrofit to assure reliable compliance. Further, initiatives to address regional haze, such as EPA's visibility rules and their requirements concerning Best Available Retrofit Technology (BART) and reasonable progress, and the increasingly stringent National Ambient Air Quality Standards (NAAQS) will affect permissible SO_2 and NO_x emission rates. Finally, individual utility company consent decrees with EPA, the Department of Justice (DOJ) and some states over alleged New Source Review (NSR) violations may influence equipment installation for some owners.

Each of these mandates is described as follows.

[1] EPA promulgated the Clean Air Interstate Rule (CAIR) in 2005 to reduce emissions of NO_x and SO_2 in the eastern U.S. Several aspects of the rule were challenged – such as how state-by-state NO_x and SO_2 reductions were calculated – and consequently in 2008 the DC Circuit court vacated CAIR. On rehearing, however, in an effort to temporarily preserve the environmental values covered by CAIR, the Court remanded CAIR without vacatur, allowing CAIR's emission reduction targets to remain in place while EPA developed an alternative. In August of 2011, EPA issued CSAPR as a replacement for CAIR, and in the process revised the methods the agency used to determine which states are subject to interstate transport limits and how to determine state-by-state reductions in NO_x and SO_2. The August 2011 CSAPR imposed an aggressive compliance schedule – requiring a first phase of NO_x reductions by January of 2012 and a phase of reductions in SO_2 by January of 2014. On December 30 of 2011, the DC Circuit court "stayed" CSAPR – but in 2014 ultimately upheld the rule. In doing so, the court ordered that implementation begin on January 1, 2015.

Cross-State Air Pollution Rule (CSAPR). The CSAPR was the primary driver for retrofit of FGD and SCR from 2012 through 2015 to limit emissions of SO_2 and NO_x to values assigned by state budgets. In January of 2017, EPA finalized revised emission limits for SO_2 and NO_x that are to be observed under CSAPR starting in 2018 and through 2021. Figure 2-1 depicts the revised state emissions budget and shows that the final NO_x emission rate assigned for 2/3 of the states either approximates or is less than 0.10 lbs/MBtu. It is likely the retrofit of additional controls will be required to meet these mandates.

Mercury and Air Toxic Standards (MATS). The MATS mandate control of mercury (Hg), fine particulate matter (as a surrogate for non-mercury metals), and acid gases (or SO_2 as a surrogate for acid gases, for scrubbed units), thereby requiring additional control equipment to be installed by 2016. This rule can require the retrofit of baghouses to control fine particles and provide a favorable environment to remove Hg and acid gases like hydrogen chloride (HCl) by the injection of activated carbon or alkali reagents. The MATS rule also prompts generating unit owners to consider upgrades or refinements to SCR and FGD, which through "co-benefits" remove Hg.

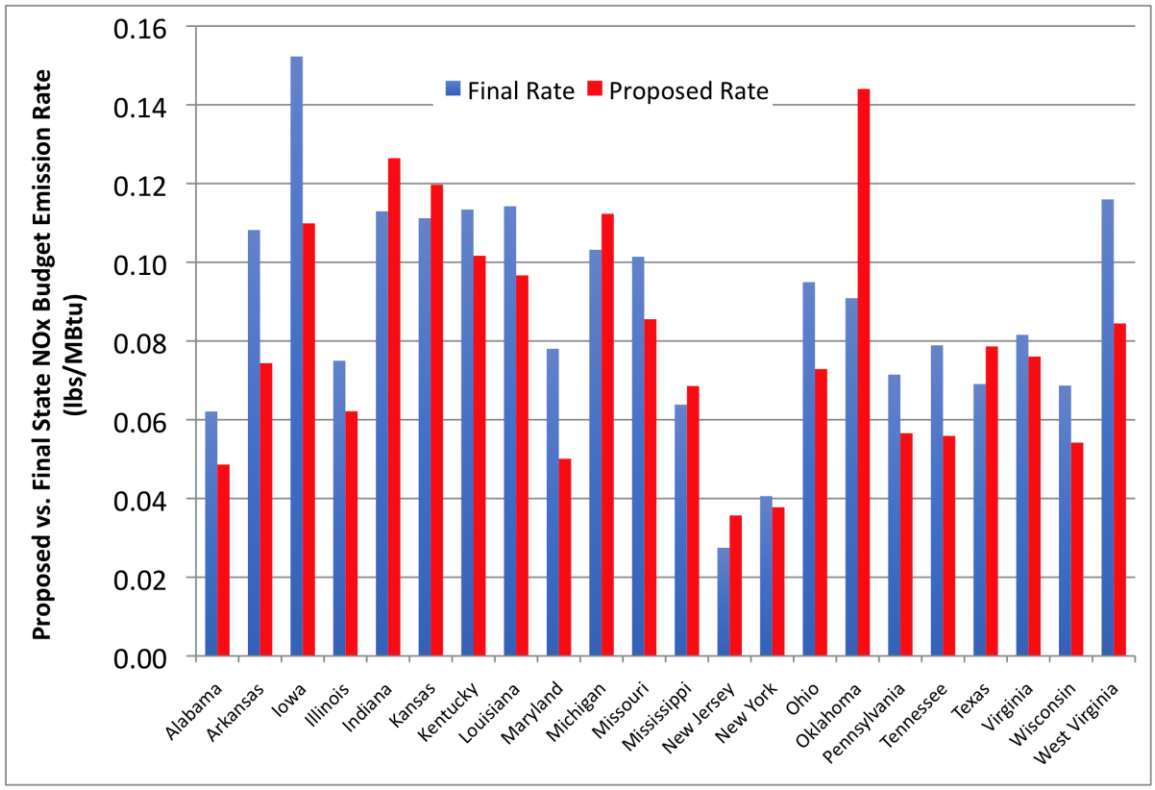

Figure 2-1. Proposed and Final State CSAPR NO_x Emissions Budgets: 2018-2023

Many units complying with MATS also have retrofit capital equipment to receive, store, manage, and disperse into the gas stream specially prepared sorbents (typically activated carbon but other formulations are used) to capture Hg. In addition, some units employed a second array of similar equipment to receive store, manage, and disperse alkali sorbents into the gas stream also for MATS. Injecting alkali compounds could have several purposes – from directly controlling

HCl to lowering SO_3 to improving the performance of activated carbon. The cost for such installations is described subsequently.

National Ambient Air Quality Standards (NAAQS). The Clean Air Act requires EPA to review the NAAQS every 5 years, which has often resulted in more stringent ambient standards. EPA's revisions to NAAQS require States with air basins exceeding the ambient standards to develop State Implementation Plans (SIPs) to improve air quality. States predominantly look to power plants to further reduce emissions.

EPA's Visibility Rules. These federal regulations require all states to review and potentially revise their SIPs to make "reasonable progress" toward the national goal of preventing future, and remedying existing, visibility impairment in Mandatory Class I Federal Areas, which include many national parks and wilderness areas, to the extent that impairment results from manmade air pollution. Consequently, individual states may require retrofit of emissions controls going above and beyond other environmental requirements, to achieve such "reasonable progress." These plans also require certain sources to meet emission limits representing "Best Available Retrofit Technology" (BART).

Although a handful of facilities have been subjected to reasonable progress requirements, BART has been the primary driver of retrofit requirements during the first ten-year planning period for the regional haze program. States that are subject to the NO_x and/or SO_2 emission reductions requirements of CAIR and CSAPR have the option of relying on compliance with those programs to satisfy their NO_x and/or SO_2 BART obligations. Most states subject to those programs chose to rely on CAIR and/or CSAPR to satisfy BART for their electric generating units. Retrofits at facilities in those states, accordingly, were not often compelled by the Clean Air Act's visibility protection requirements. Facilities in states not subject to CAIR or CSAPR, primarily in the West, have experienced the most regulatory impacts as a result of the BART.

Settlements Regarding Alleged NSR Violations. In order to resolve allegations by the U.S. EPA that they have violated provisions of the CAA regarding NSR, owners of some units have entered into settlement agreements requiring the installation of FGD and SCR on a more accelerated schedule than required under other provisions of the CAA.

2.3 FGD AND SCR INVENTORY

Figures 2-2 to 2-7 report the inventory of FGD (both wet and dry) and SCR process equipment that has been installed through 2016 to meet regulatory mandates. Figure 2-2 shows the generating capacity (MW) that was newly retrofit with either wet or dry FGD each year from 2002 through 2016. The peak of 20,000 MW or more each year occurred in 2008, 2009, and 2010. Figure 2-3 presents the cumulative capacity equipped with FGD since 2001 – approaching 150,000 MW by the end of 2016. Added to the existing inventory of almost 96,000 MW of FGD associated with new units installed prior to 2002, about 250,000 MW of the U.S. coal-fired fleet are be equipped with FGD by 2017.

Figures 2-2 and 2-3 reflect FGD process equipment installed without accounting for equipment removed due to retirements. Approximately 2,400 MW of FGD-equipped units were retired between 2012 and 2016.

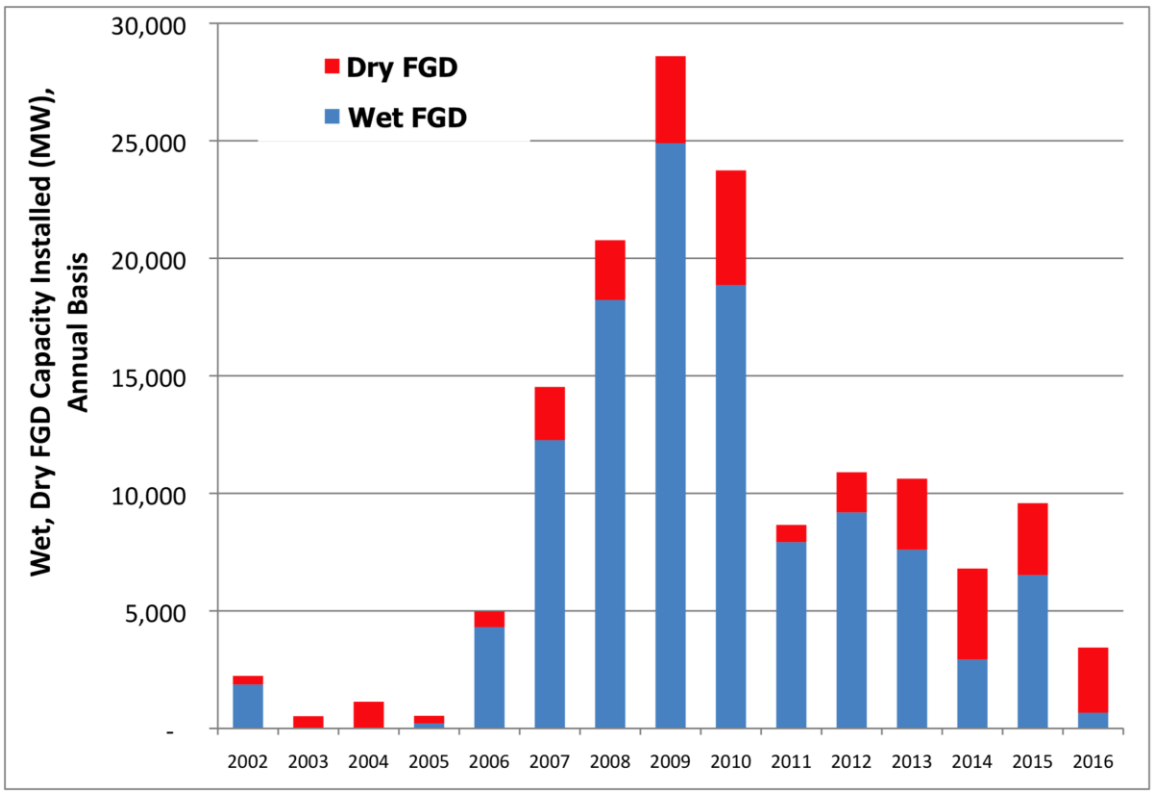

Figure 2-2. Historical Wet and Dry FGD Capacity: Installed MW per Year

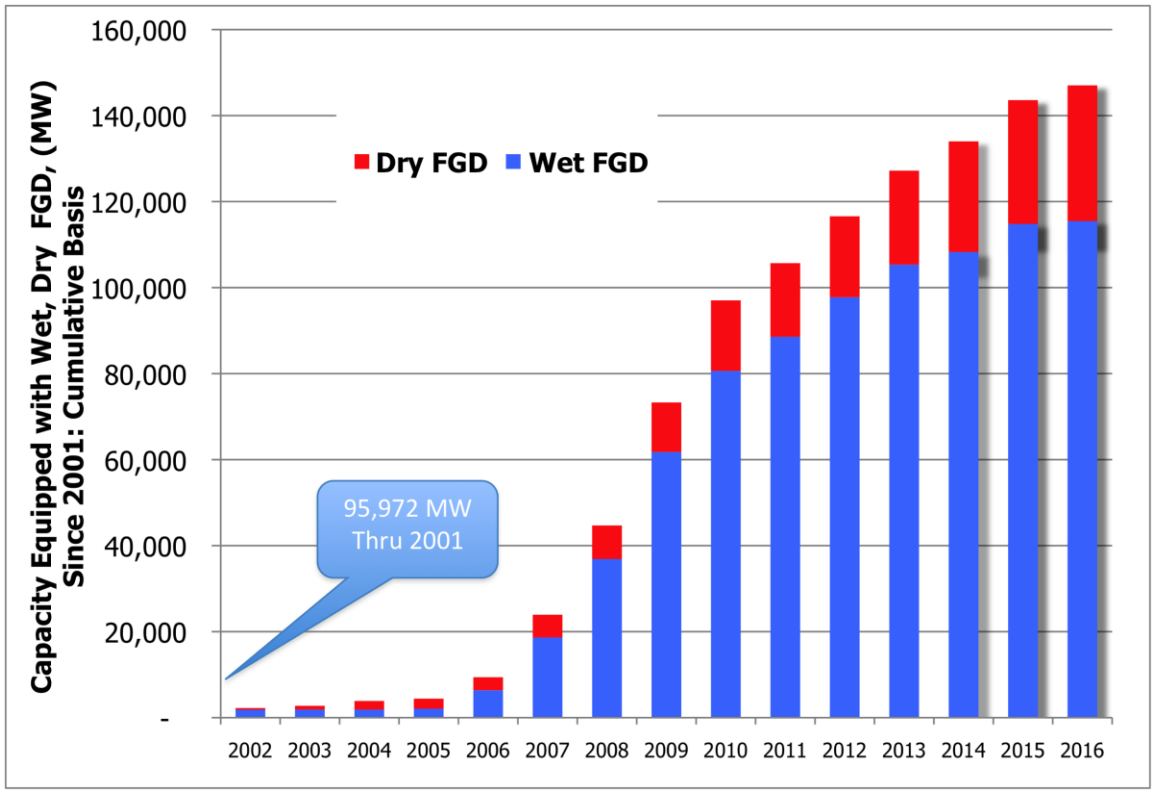

Figure 2-3. Historical Wet and Dry FGD Capacity: Cumulative MW per Year

The trends in SCR installation are equally important. Figure 2-4 shows the annual generating capacity newly retrofit with SCR over the same time period – 2002 through 2016. Since the peaks in 2002 to 2004, the generating capacity retrofit with SCR in each year ranges between about 3,000 and 12,000 MW. Figure 2-5 presents the cumulative generating capacity equipped with SCR which exceeds 140,000 MW by the end of 2016.

Figures 2-4 and 2-5 reflect SCR process equipment installed without accounting for equipment removed due to retirements. Approximately 3,100 MW of SCR-equipped units were retired between 2012 and 2016.

An additional factor prompting SCR and FGD retrofit is the contribution to removal of Hg and other hazardous air pollutants (HAPs) by "co-benefits". Specifically, SCR is known to prompt Hg oxidation to a soluble state (mercuric chloride [$Hg(Cl)_2$] thus increasing removal by wet FGD. The degree of Hg oxidation is determined by many factors, including the inherent content of bromine (Br) in the fuel. The "co-benefits" can be increased by adding bromine to the process (e.g. calcium bromide to the fuel) to prompt the conversion of elemental Hg (Hg^0) to the oxidized, soluble form of Hg [$Hg(Cl_2)$]. In addition, special-purpose additives are sometimes introduced into the FGD liquor to improve the retention of Hg removed from the gas stream.

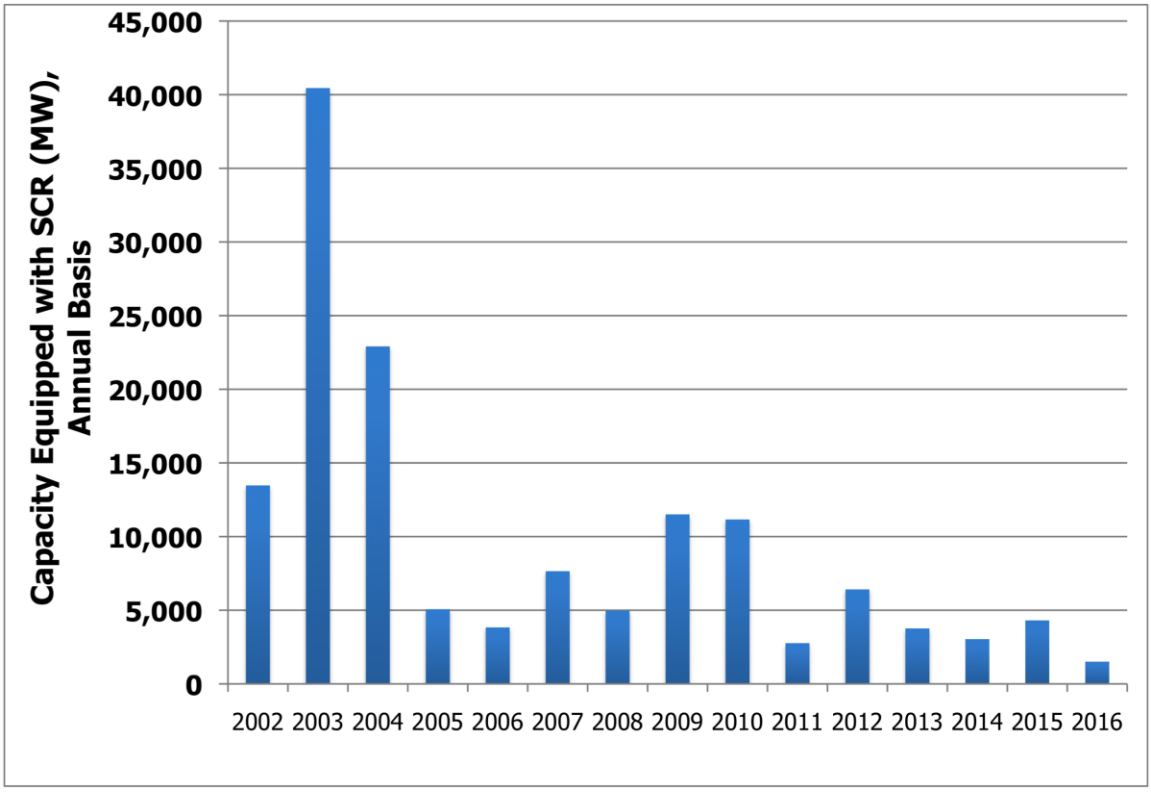

Figure 2-4. Historical SCR Capacity: Installed MW per Year

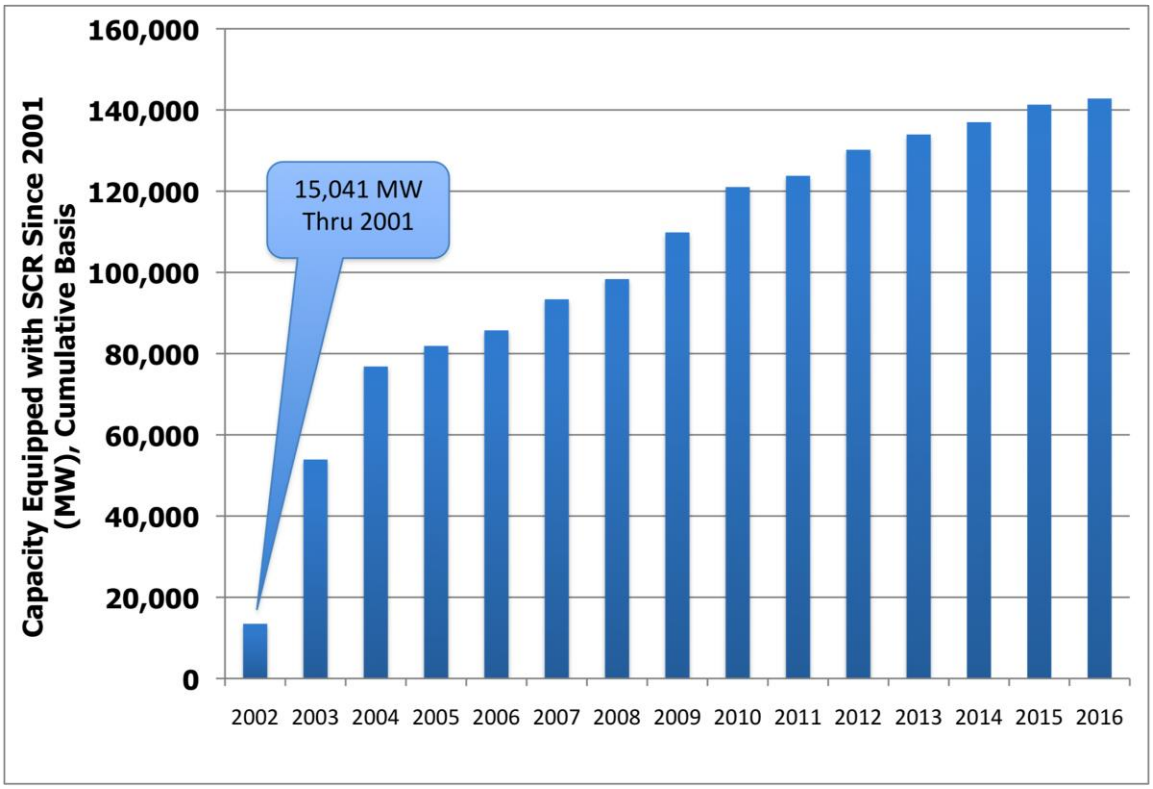

Figure 2-5. Historical SCR Capacity: Cumulative MW per Year

The inventory of units equipped with both SCR and FGD is depicted in Figures 2-6 and 2-7, reporting annual and cumulative generating capacity, respectively. Both figures identify the installation year as the first year of operation with both control systems. Unlike Figures 2-1 and 2-2, the data in Figures 2-3 and 2-4 reflect FGD installed prior to 2002. (Thus, almost all of the FGD equipment reported for the years 2003 through 2005 reflect FGD installed prior to 2002.) Figure 2-7 shows more than 140,000 MW of capacity is equipped with both SCR and FGD through 2016.

Approximately 1,250 MW of the generating capacity equipped with both SCR and FGD as depicted in Figures 2-6 and 2-7 were retired between 2012 and 2016.

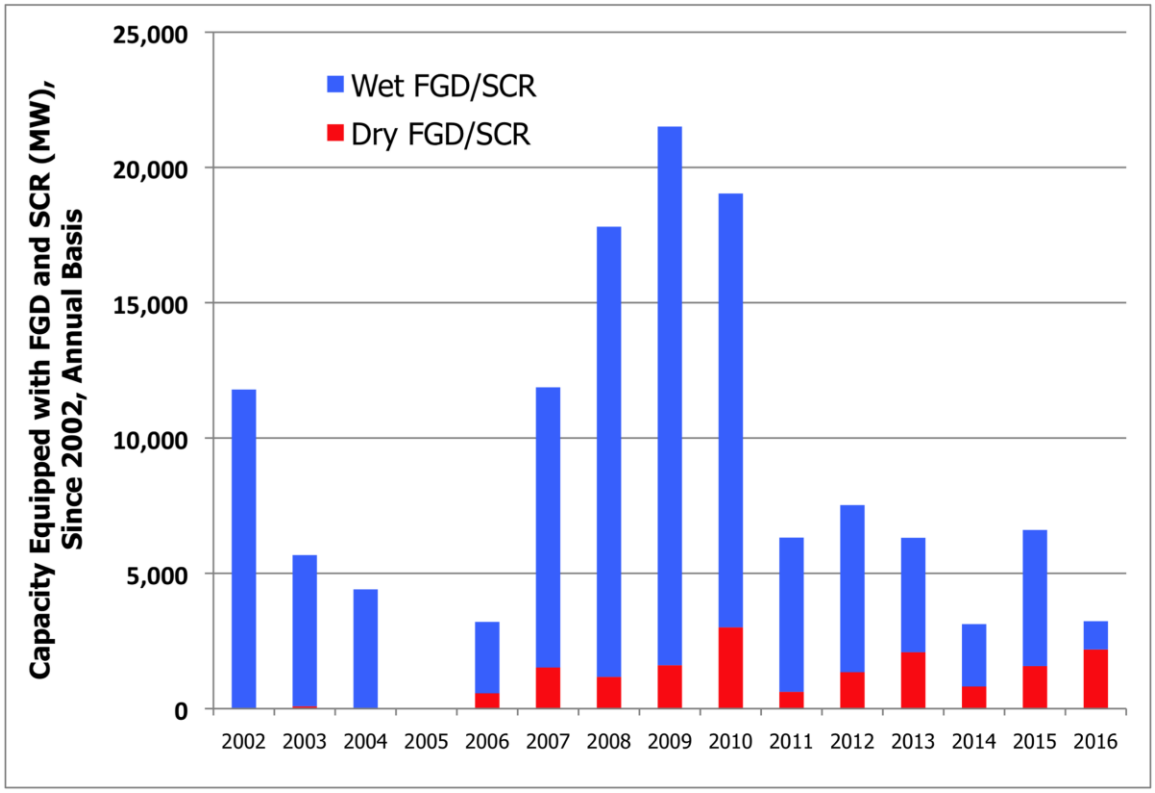

Figure 2-6. Units with Both FGD and SCR: Installed MW per Year

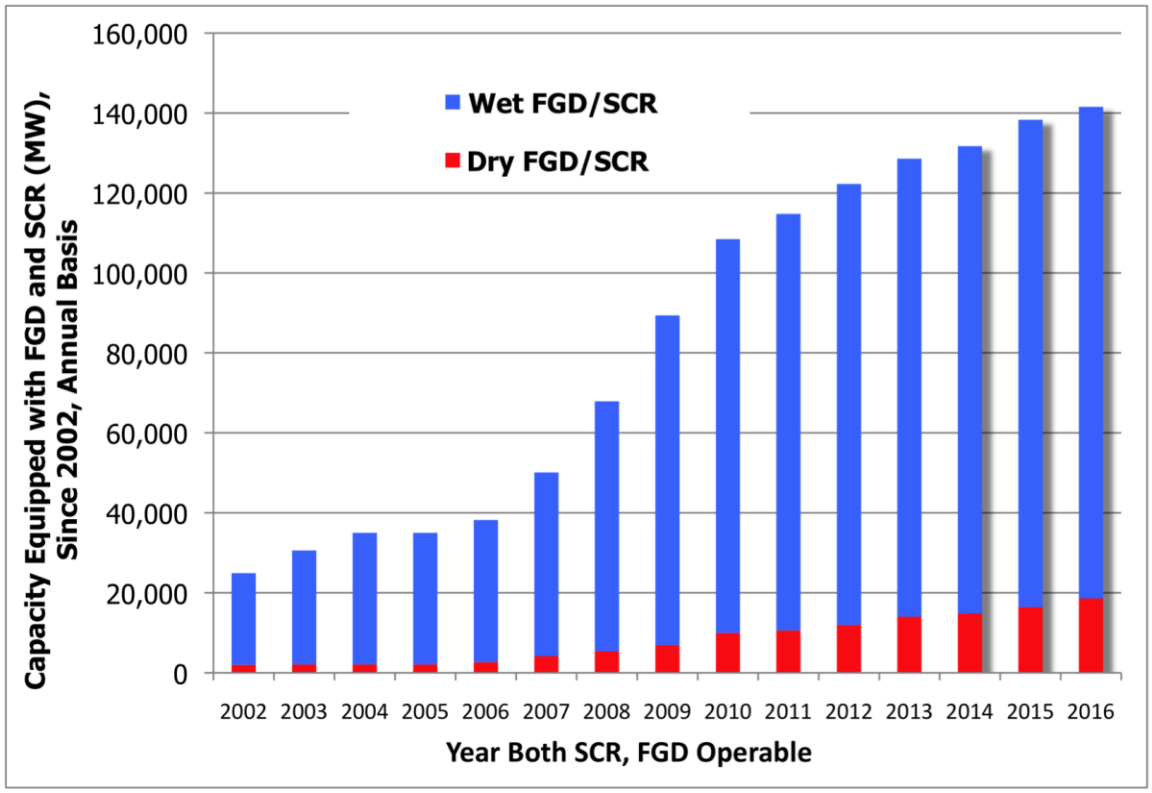

Figure 2-7. Units with Both FGD and SCR: Cumulative MW per Year

SECTION 3

FACTORS AFFECTING REPORTED CAPITAL COST

This section reviews the factors that affect the capital cost for air pollution control equipment. These factors include (a) the methodology by which costs are developed, (b) how cost is escalated over time, and (c) features of the host power stations.

3.1 CAPITAL COST REPORTING METHODOLOGY

An accurate accounting of the cost for air pollution control equipment requires a consistent methodology to report and treat costs. Both the direct and indirect costs to acquire the process, and the fixed and variable operating costs must be accounted for. EPRI's Technical Assessment Guide[2] provides one such methodology which has served as a basis for analysis conducted by the Department of Energy (DOE), EPA, and other organizations.

The focus of this report is installed capital cost for environmental control equipment. The capital cost consists of several key components, defined as follows:

Process Equipment. The reaction vessels, absorbers, reagent receiving and supply systems, process controls, and initial inventory of catalysts, reagent, and filter (for baghouses) comprise this category of cost.

General Facilities. The land occupied by the process, access roads, support buildings and laboratories make up general facilities.

Installation Charges. These costs include construction and installation labor, materials, and special equipment (rental of cranes, etc.).

Engineering Charges. Engineering charges include selecting the process, defining the specific conditions at the site, optimizing the process design for the site, integrating the process design with balance-of-plant equipment, and procurement.

Owner's Costs. Owner's costs include staff for management, engineering, and developing proper operating practices.

Finance, Other Charges. Finance charges are accounted for through the Allowance for Funds Used During Construction (AFUDC), which reflects financing costs during construction when the equipment is not in use. In addition, some states (e.g., New Mexico) impose a "gross receipts" tax, which is essentially a sales tax on industrial equipment.

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[2] *TAG™ Technical Assessment Guide: Electricity Supply – 1993*, EPRI TR-102275-V1R7, Volume 1: Rev 7, June 1993.

Preproduction, Inventory Capital. Spare parts and the initial (typically 30 day) supply of reagent and chemicals comprise this charge.

Not all reported environmental control costs reflect a complete scope of equipment that is required. For example, Tampa Electric in 1998 reported installing FGD for less than $100/kW,[3] but this cost did not include reagent preparation equipment or other support facilities that were previously installed for two earlier FGD absorbers. Similarly, the cost for PacifiCorp to convert an existing hot-side ESP at the Wyodak station to a fabric filter does not reflect the cost of retrofitting a stand-alone installation. Public Service of New Mexico recently expended significant funds to provide state-of-art wet FGD at the San Juan Generating Station that uses forced oxidation to generate a gypsum byproduct; however, this work utilized components of the legacy Wellman-Lord process preventing the true cost of a stand-alone process to be determined.[4]

3.2 CAPITAL COST ESCALATION

Capital cost is adjusted to account for the escalation over the time periods in this analysis. The earliest periods for which costs are reported starts in 1995 for the "Phase 1" retrofit of flue gas desulfurization processes, per the 1990 Clean Air Act Amendments. The costs incurred in these years are escalated into end-of-year 2016 basis using the FRED GDP Implicit Price Deflator.[5]

3.3 SITE AND DESIGN FACTORS

This report cites single-point costs for environmental controls based on what an owner has incurred to complete a retrofit project, or estimates of final construction costs for projects in the final stages of completion. Using a single point to represent cost for an environmental control system suggests a definitive understanding of costs that does not exist. In reality, the cost for such complex equipment varies over a wide range, even for a narrowly defined specification or set of process conditions. This variability will be evident in graphical depictions of process cost for the 2012-2017 timeframe presented in Sections 5-7, and in several examples from earlier time periods contained in the Appendix.

A brief summary of site-specific factors, and how they impact capital cost, is as follows:

Fuel Composition. The fuel defines the volume of combustion products, the content of particulate matter, SO_2, and NO_x, and the composition of fly ash. These flue gas characteristics define process equipment size and cost. For example, Powder River Basin (PRB) or other sub-bituminous coals can generate up to 30% greater volume flue gas, compared to an eastern bituminous coal, to be processed for the same generating capacity. The quantity of sulfur to be processed and the fate of the FGD byproduct – extent of dewatering, and preparation for resale or disposal – also affect cost. For SCR reactors, the fly ash composition and presence of trace

[3] "Tampa Electric announces plans to reduce emissions from Big Bend Units One and Two", New Release, July 20, 1998, TECO/Tampa electric, available at: http://www.tampaelectric.com/company/mediacenter/article/index.cfm?article=110

[4] San Juan Shaves Cost from FGD Retrofit, Power Engineering, June 1, 1998. Available at http://www.power-eng.com/articles/print/volume-102/issue-6/features/san-juan-shaves-costs-from-fgd-retrofit.html

[5] https://fred.stlouisfed.org/series/USAGDPDEFAISMEI

elements such as arsenic and phosphorous can determine catalyst surface area, catalyst volume, and reactor arrangement.

Table 3-1 compares the composition of three coals widely used in the U.S. These coals represent the categories of (a) eastern bituminous, (b) Powder River Basin, representing the most popular subbituminous coal, and (c) lignite coal from Texas. Table 3-1 shows that the heating value per unit mass of coal (i.e., Btu/lb), which dictates much of the design, varies significantly both between and within the three coal ranks. It is not possible to designate any one coal as more problematic than another – each has features that challenge the design and operation of air pollution control equipment.

Specifically, eastern bituminous coals generate relatively low flue gas volume per unit of output, but can contain large amounts of sulfur that elevate FGD cost. Further, arsenic content can be high, which if not mitigated by the inherent alkalinity from calcium, will accelerate catalyst deactivation. In contrast, PRB coals generate a substantial volume of flue gas per unit output, increasing the size of reaction vessels, but contain less sulfur compared to bituminous coals, lowering the mass of sulfur byproduct that must be removed. The NO_x generated by PRB is relatively low, minimizing the catalyst volume for SCR process equipment.

Texas lignite composition is highly variable, and can contain substantial amounts of high silica-containing ash, which erodes ductwork and catalyst. The lower gas velocities generally required for this application increase equipment size and cost.

The composition of fuel drives the design of the boiler and environmental control system. In competitive wholesale power markets, the least cost fuel is the most likely to be selected, even if the composition requires supplemental investment for environmental controls or elevates non-fuel variable operating costs. The most notable example of this trend was witnessed in early phases of compliance with the 1990 CAAA, when the use of low sulfur "compliance" coals was predominant. Over time, many plant owners invested in FGD equipment to enable using higher sulfur content - but less costly - coals. This relationship between coal cost and composition can also be observed for constituents such as Hg and arsenic (As), both of which can affect environmental control capital and operating cost.

Further discussion of how coal properties affect environmental control cost is presented in the subsequent sections reporting FGD, SCR, and fabric filter cost.

<u>Site Congestion and Retrofit Difficulty</u>. Limited space on-site complicates construction – there is less access to "lay-down" equipment prior to erection, locate cranes, and efficiently use labor. As a result installation time is extended, increasing capital cost. A site with numerous older units will invariably incur high retrofit costs due to limited access. This cost penalty can be partially offset if the gas flow from multiple small units is treated in a single device, or if the individual units feature significant generating capacity and can derive economies-of-scale from a similar design and construction management.

Table 3-1. Comparison Proximate Analysis, Select Ash Constituents, and Trace Constituents of Three Commonly Used U.S. Coals[6]

	Units	Texas Lignite	Powder River Basin	Eastern Bituminous
Proximate (%, as-received)				
Moisture	%, as received	26-36	20-27	4-8
Ash	"	8.5-22	4.8-6.1	7-15
Fixed Carbon	"	15.4-31	35-51	45-50
Volatiles	"	21-38	34-44	28-40
Sulfur	"	0.76-2	0.20-0.50	1.2-4.3
Heating Value	Btu/lb	5,768-7,848	8,600-9,200	10,300-13,000
Selected Ash Analysis				
PO_5	%	0.10-0.20	0.2-1.9	0.04-0.25
SiO_2	"	25-56	21-49	42-56
Fe_2O_3	"	0.09-16	4-10	5-19
Al_2O_3	"	12-25	14-23	20-28
TiO_2	"	1.0-2.1	0.8-2.4	0.6-1.5
CaO	"	6-31	9-33	0.6-6
MgO	"	1.4-3.6	3.2-5.5	0.5-1
K_2O	"	0.2-1.0	0.4-1	1.6-2.5
Na_2O	"	0.2-1.0	2-7	0.4-1.6
SO_3	"	6-21	5-9	0.3-4.8
Selected Trace Elements				
As	(mg/kg)	2-7	1-5	4-15
Cl	"	<100	<100	1,300
Hg	"	0.18-0.32	.05-0.1	0.04-0.2
Selenium		1-8	0.10-0.30	0.5-4

[6] Coal composition derived from several sources. *Steam, It's Generation and Use,* 40th Edition, 1992, The Babcock & Wilcox Company. *Combustion Fossil Power*; Fourth Edition, 1991, Combustion Engineering, Inc. Data augmented with coal composition shared by various Owners contributing cost information to this document.

Figure 3-1 shows one of the more constrained sites in the U.S. – DTE Energy's Monroe Station. The site is relatively complex – there are four "sister" units generating between 817-822 MW each, with the site bordered by inland waterways. DTE Energy successfully retrofit wet FGD and SCR to each of these units over a 6-year period, deploying the same process design based on utilizing a single absorber for each unit.

Figure 3-1. DTE Energy Monroe Station: Example of Constrained Site

The wet FGD retrofit work at Monroe was complicated by the relatively large SCR reactors that had been previously retrofit to each generating unit. The complex site contributed to elevating the cost for FGD above that typical for a less constrained site.

Figure 3-2 depicts LG&E Mill Creek Unit 4, revealing the retrofit of both a fabric filter and an FGD absorber. Mill Creek Unit 4 represents one of the less constrained sites, being an "end" unit with access for equipment location and construction activities. The physical attributes of Unit 4 are not shared by Units 1-3 at the LG&E Mill Creek Station – Units 1-3 were retrofit with fabric filters and wet FGD and offered a more challenging physical access compared to Unit 4.

Figure 3-2. LG&E Mill Creek Unit 4: Retrofit Fabric Filters, Wet FGD

Existing Site Auxiliary and Support Facilities. FGD and SCR process equipment demand auxiliary power, steam, and compressed air. As the availability of these consumables at a site varies, additional infrastructure to supply and distribute these consumables may be necessary. The most costly can be new power distribution infrastructure including transformers, switchgear and/or "motor control centers." The escalation in price until 2008 of copper-containing electrical subsystems has contributed to cost increases; during periods of peak copper pricing electrical infrastructure escalated from 5-6% of an FGD budget to more than 10%.

Flue Gas Draft System Upgrades. The retrofit of environmental controls will change the static pressure within the ductwork, which may require upgrades to fans, new fan motors, upgraded electrical systems, and strengthening of ductwork, ESPs, and boiler walls. The upgrade and strengthening of ductwork and boiler walls is necessary to prevent collapse or implosion.

Waste Water Treatment Requirements. For wet FGD, the need to treat process discharge water varies depending on permitted limits. Zero-water discharge requirements can impose large costs on the entire FGD slurry treatment and dewatering systems, and may possibly interfere with FGD chemistry. For wet FGD process equipment installed at a site in North Carolina, wastewater treatment facilities comprised between 9 and 14% of the total capital cost. The design of a waste water treatment system has been a key point of contention in the retrofit of wet FGD to the

PSNH Merrimack Station, contributing in part to relatively high FGD process cost. Waste water treatment equipment alone for this station has been estimated to cost $23M.[7]

Stack: Rebuild or Replace. Retrofit of wet FGD process equipment can require replacement of or a major rebuild of the stack. Flue gas treated by wet FGD poses corrosion and deposition potential, due to relatively low saturation temperature and content of SO_3. The least cost solution can involve a new stack rather than retrofitting corrosion-resistant liners to an existing stack.

Equipment Sparing and Redundancy Philosophy. The operating strategy of the owner, and the cost incurred for an FGD outage determines the equipment sparing and redundancy. Sparing philosophy can affect capital cost by 10-20%. Operators with sufficient margin in meeting the SO_2 or NO_x "cap," or for whom SO_2 or NO_x "allowances" are available, may choose to lower capital cost by minimizing redundant equipment. Conversely, operators for whom access to SO_2 or NO_x allowances is limited or costly may elect to invest in more spare equipment.

Future operating scenarios for many units project lower capacity factors compared to present base-load operating modes. The reduction in capacity factor may include an increased number of start/stop modes, and more frequent "ramping" between stable modes. This change in operation may impart more stress to process equipment, requiring a sparing and replacement philosophy that should be updated to account for significant part load and load ramping operation.

Materials of Construction. Special-purpose materials can resist corrosion and erosion, and support high reliability, but elevate capital cost. Specifically, using high alloy containing steels or rubber-lined absorber vessels or pumps will increase reliability. The ability of a fluid to corrode, erode, or otherwise compromise piping must be considered when selecting construction materials. For wet FGD using higher alloy and lined equipment adds 10-20% to project capital cost.

Site complexity is perhaps the most important of these preceding factors. Capital costs continue to escalate because sites where FGD and SCR are to be retrofit are more complex than many prior applications for several reasons. The largest generating capacity units with the best site access have already been equipped with FGD and SCR, leaving smaller and older units for retrofit today.

[7] Expert Report of John H. Koon in the Matter of Comments on the NPDES Permit for PSNH's Merrimack Station (2012), February 24, 2012, available at *www.epa.gov/region1/npdes/**merrimack**station/pdfs/.../PC-6.pdf*

SECTION 4

MATERIAL AND LABOR ESCALATION

The cost of basic material and labor has escalated since the year 2000, most notably from the year 2003 through 2010. The escalation of material prices in 2008 and 2009 has abated, with most prices "relaxed" from peak values observed at that time. Labor costs have not decisively changed from peak values. This section discusses how material prices and labor costs impact equipment cost.

4.1 BASIC MATERIALS

Basic materials required to fabricate air pollution control equipment are steel and iron ore for products such as structural steel and ductwork, and specialty or "non-ferrous" metals such as copper for wire and cable, and nickel and molybdenum for processed alloy metals. These material inputs are key to determining the price of finished equipment such as pumps, valves, piping, instrumentation and control systems.

The cost for these construction materials escalated rapidly in the first decade of this century, and is a key contributor to the increase in emissions control costs. The cost for most of these materials subsided around 2010, although since then modest but consistent world-wide economic growth has restored some prices to near their peak values.

Figures 4-1 and 4-2 present the change in the Federal Reserve Bank of St. Louis (FRED) Producer Price Commodity Index for (a) steel and iron ore, and (b) non-ferrous steel products (1982 prices as a base case).[8] Figure 4-1 shows steel and iron ore prices beyond 2008 to be at least double those of 2000, with a 2008 spike to three times the year-2000 value. Figure 4-2 shows non-ferrous metals to have incurred this level of escalation two years earlier, in 2006. As shown in Section 2, this time period corresponds to both the peak interval of FGD installation and to a second, smaller peak of SCR installation. By 2015 the relative prices of both steel and iron ore and non-ferrous materials relaxed to less than twice the year-2000 prices.

FGD projects implemented from 2006 through 2008 incurred schedule delays due to limited availability of equipment for reagent preparation, slurry recirculating pumps, agitator pumps, certain forced and induced draft fans, and stack construction. Equipment availability rarely imposes similar limits in the present market.

[8] https://fred.stlouisfed.org/series/PPICMM

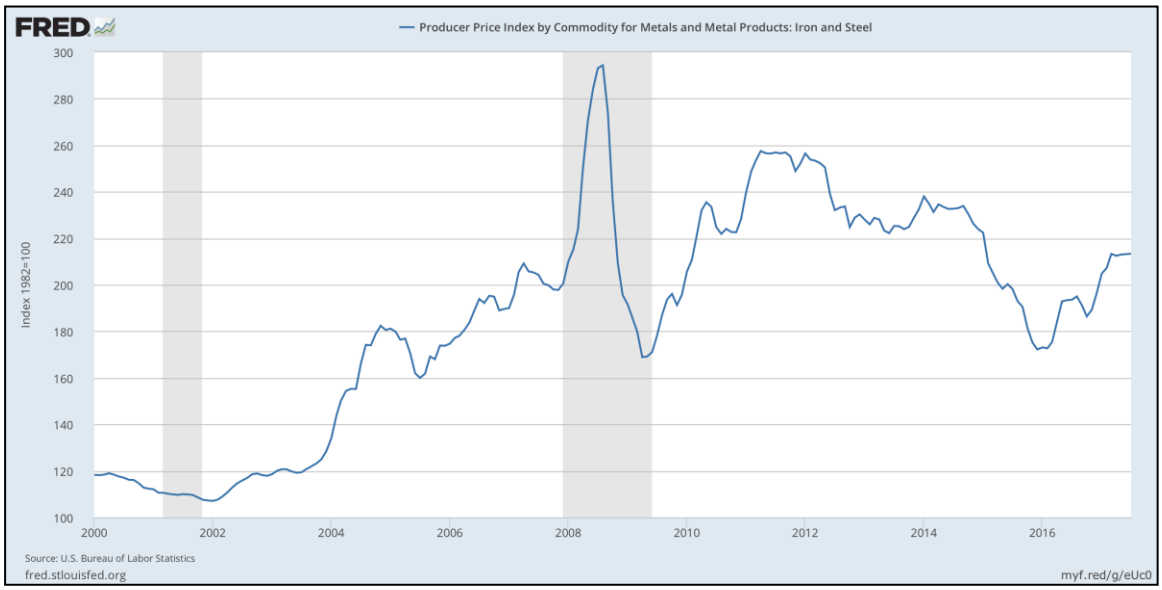

Figure 4-1. Steel and Iron Ore Cost Index (Base Year 1982)

Figure 4-2. Primary Non-Ferrous Metals Price Index (Base Year 1982)

4.2 CONSTRUCTION LABOR

The availability of qualified field labor has been a historical concern to support the timely and effective installation of process equipment. Labor rates for installing process equipment at power stations can be a premium and during periods of strong demand can escalate rapidly. The rate of escalation can be particularly problematic for crafts with the lengthy apprenticeship programs (e.g., boilermakers), as well as crafts with less restrictive training (pipefitters, electricians). Escalation in specialty construction labor was documented by the industry through 2007,[9] but such escalation has abated in recent years.

Figure 4-3 presents wage escalation for private construction workers observed since 2000 as reported to the Federal Reserve Bank of St. Louis.[10] This category of laborer reflects broad construction trades, not necessarily the specialized trades for heavy equipment construction, but it is indicative of utility construction costs. This escalation in labor wage rate in Figure 4-3 is equal to an annual rate of 3-4% from 2008 through 2017.[11]

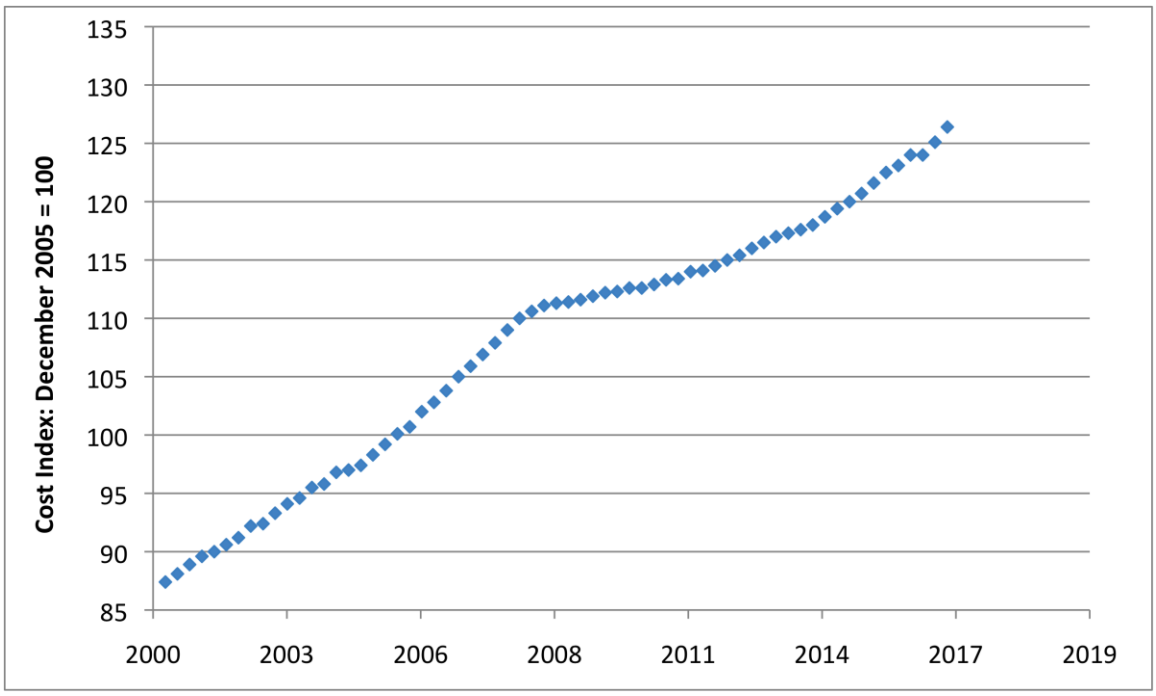

Figure 4-3. U.S. Bureau of Economic Analysis Private Industry Construction Worker Labor Rate Index

The labor rate escalation shown in Figure 4-3 will increase installed equipment cost but is not a dominant factor as experienced prior to 2008.

[9] *Building New Baseload Generation in the Midwest,* MMEA Presentation, Black & Veatch, May 11, 2006.
[10] https://fred.stlouisfed.org/series/ECICONWAG#0
[11] See Table 5, "Natural Resources, Construction, and Maintenance", change registered in September 2009 versus September 2008, U.S. Bureau of Labor Statistics, www.bls.gov/news.release/eci.t05.htm

SECTION 5

FLUE GAS DESULFURIZATION COSTS

This section discusses capital and operating costs for wet and dry FGD process equipment, reflecting units installed from 1995 through 2017. As noted, the operation of wet or dry FGD also can support Hg removal via the "co-benefits" described previously; the cost impact of utilizing this equipment for Hg removal is not addressed in this report.[12]

5.1 FGD CAPITAL COSTS

The capital cost reported in this section describes a complete scope of work, including all indirect charges and AFUDC, escalated into end-of-year 2016 basis using the FRED GDP Implicit Price Deflator.[13]

It should be emphasized these data may not necessarily reflect comparable cases – each unit will differ with respect to inlet SO_2, SO_2 removal, fuel type, absorber design, dewatering and byproduct management, and balance-of-plant equipment. The general cost trend shown in the figures is believed to reflect the industry average.

5.1.1 Wet FGD

Figure 5-1 presents capital cost data for four deployment periods, from 1995 through 2017. Capital cost (unit basis, or $/kW) is displayed versus generating capacity. Three curves represent capital cost versus generating capacity for the earliest deployment periods. The most recent installations – in 2012 or planned through 2017 – are represented by thirteen data points. Most FGD units employ limestone reagent, and with few exceptions, are designed for 95% SO_2 removal, forced oxidation treatment of byproduct, and are equipped with mist eliminators.

Curve A represents the capital cost for units that started commercial service prior to January 1995 to comply with Phase 1 of acid rain rules. Curve A is based on the capital cost of 15 units, for which 11 provide 95% or greater SO_2 removal. All units but two employ limestone as reagent, with the remainder using magnesium-enhanced lime. Curve A shows for these early installations that unit capital cost ($/kW) was essentially invariant with increasing generating capacity. Further, capital cost widely varies around the average values shown. Appendix A presents the 15 data points for Curve A which (on a 2016 dollar basis) show the average value of approximately $350/kW represents costs that vary mostly between $300 and $495/kW.

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[12] Operating costs for a wet FGD process directed to maximize Hg removal can increase due to additional monitoring of the oxidation/reduction potential and other parameters that affect Hg removal, or the addition of special-purpose compounds to minimze Hg re-emission. Dry FGD operating costs can increase with the need to inject activated carbon or other sorbents to remove Hg within the filter environment.

[13] https://fred.stlouisfed.org/series/USAGDPDEFAISMEI

Curve B represents the capital cost for units that started commercial service over the ten-year period from 1997 through 2007. The predominant use of low sulfur Power River Basin coal for compliance during this time period minimized the number of wet FGD processes that entered commercial service. Eleven units provide the basis for Curve B which exhibits a more conventional relationship between generating capacity and unit capital cost. Appendix A presents the individual data points for Curve B, showing the extent the cost data vary around the mean values (e.g., a low of about $220/kW to $480/kW, on a 2016 dollar basis).

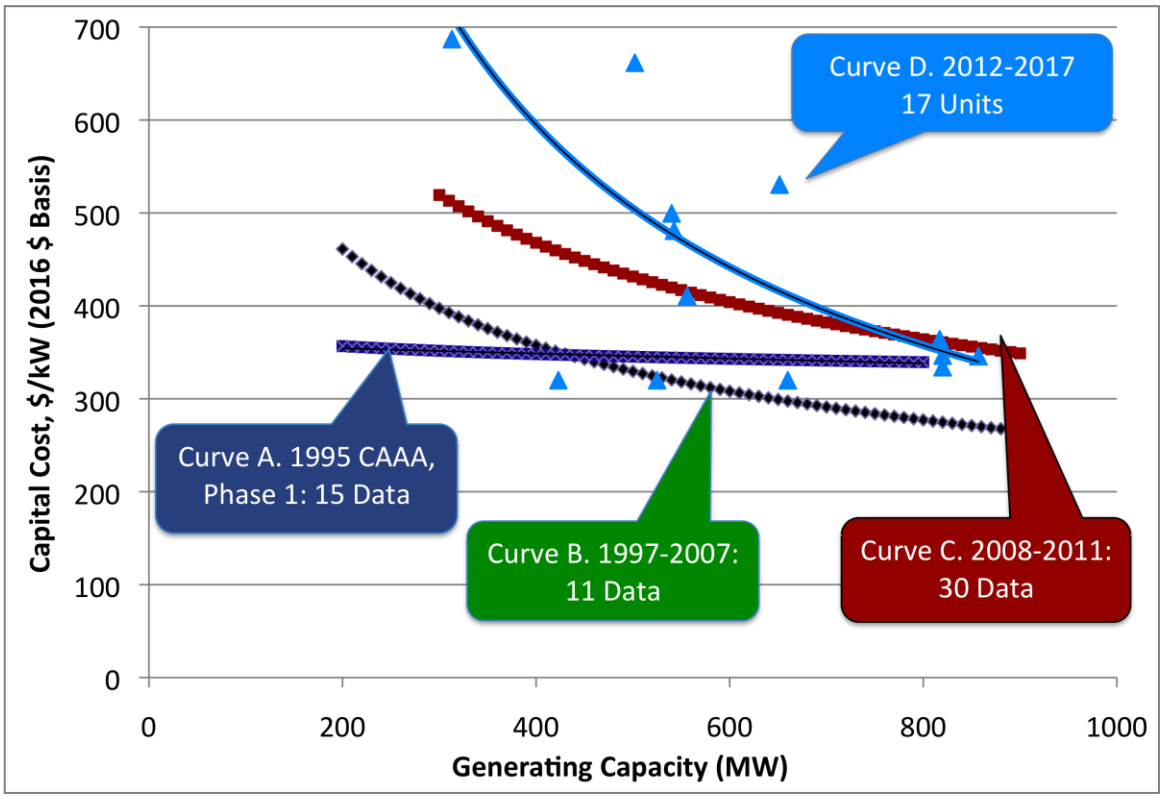

Figure 5-1. Wet FGD Process Equipment Cost (2016 Basis): Four Periods of Deployment

Curve C presents capital cost for units that started commercial service between 2008 and 2011. Most of these units were deployed to meet Phase 1 of the CAIR mandates; other units were constructed to comply with NSR consent decrees agreed to with the Department of Justice. A large number of units began service in this time period – Curve C is based on 30 separate FGD facilities. Significant variability in the 30 data points is exhibited around the mean values.

Capital cost for the most recent inventory of FGD processes – those installed from 2012 and planned for startup through 2017 – are represented by thirteen points in Figure 5-1.

These data in Figure 5-1 suggest the following observations:

<u>Capital Cost Has Escalated with Time</u>. The cost to retrofit wet FGD has generally increased since deploying the Phase 1 retrofits, particularly for units of intermediate generating capacity (e.g. 300-500 MW). For example, for a 500 MW unit the average capital cost incurred for FGD

installed by 1995 compared to units installed through 2007 is similar. However, the unit cost for FGD increases by $100/kW or more for units installed in the 2008-2011 and the 2012-2017 timeframe.

Reported costs for wet FGD for large units approximating 800 MW are all within about $100/kW and do not depend on the time of installation. However, there are few data representing costs for this generating capacity and the paucity of data may confound any trend in results.

Most Capital Cost Data Exhibit Significant Economies of Scale. With the exception of the Phase 1 FGD retrofits (described by Curve A), the minimum capital cost per unit generating output ($/kW) is incurred at highest generating capacities. This observation is consistent with historical trends for process equipment. That Phase 1 FGD retrofits did not exhibit economies-of-scale could be due to the evolving nature of FGD technology at the time, in which subordinate equipment (e.g., pumps for spray towers, solids byproduct handling equipment) were designed for large capacities by replicating "identical" modules, thus not extracting cost advantages.

FGD processes retrofit by 1995 to meet the Phase 1 acid rain rules likely are not typical of subsequent designs. The 1990 CAA Amendments was the first federal mandate to create SO_2 emission allowances – enabling averaging or production of SO_2 emission credits. Many Phase 1 FGD processes were designed for 93% SO_2 removal and greater, and employed single FGD absorber towers to treat up to 700 MW of flue gas. The use of a single absorber tower for such large units was not unprecedented – but there was limited experience from which to derive a commercial design. It is possible the Phase 1 acid rain units were designed conservatively, thus economies-of-scale were negligible.

The capital costs represented in Figure 5-1 for wet FGD will likely increase in future years due to evolving EPA effluent limitation guidelines (ELG). The ELGs, first proposed in June of 2013 and finalized on November 3, 2015, limit the content of wastewater constituents discharged from numerous plant operations – but perhaps most significantly affect wet FGD wastewater. FGD process waste is comprised of effluent from purging the FGD process (e.g. scrubber liquor) to control accumulation of trace species, and other liquid streams generated from the dewatering or separation of byproducts. EPA is currently reconsidering the ELGs and has postponed the compliance dates for certain of its new effluent limitations, including those for FGD wastewater. Depending on the ELGs that EPA adopts as a result of its reconsideration, the cost of control equipment required to treat wet FGD wastewater in the future could be significant.

5.1.2 Dry FGD

Figure 5-2 depicts capital cost for lime-based dry FGD presented as a function of generating capacity. The costs represented include the reagent supply equipment, the spray dryer absorber vessel, and the fabric filter to capture both fly ash and particulate from sulfation. Similar to the case for wet FGD, these costs are expressed in 2016 dollars, and reflect all direct and indirect charges. State-of-art dry FGD equipment is capable of 93-95% SO_2 removal; the equipment represented in Figure 5-2 represents a range (80-93%) of SO_2 removal. In some cases the particulate collector (typically an ESP) is retained in the original configuration, preceding the spray dryer absorber, and continues to collect fly ash generating a marketable byproduct. The advantage of this arrangement is the spray dryer absorber and fabric filter – operating

downstream of the original ESP – can utilize lime reagent more effectively and produce less SO_2-derived byproduct.

Reported dry FGD capital costs are presented for the time periods of 2008 through 2017 – partitioning the costs further by time did not reveal any difference. Reported capital costs for units installed between 2008 and 2017 vary widely and do not enable a meaningful correlation between incurred cost and generating capacity. Data presented in Figure 5-2 reflect two different dry FGD design concepts. The first concept represents "conventional" dry FGD utilizing the widely applied spray dryer absorber (SDA). A second concept, referred to as "Compact Dry FGD", occupies a smaller footprint than the conventional SDA approach and is also represented by Figure 5-2. The compact dry FGD design is commercially referred to as a Circulating Dry Scrubber (CDS) or Novel Integrated Desulfurization (NID) concept, depending on the supplier.

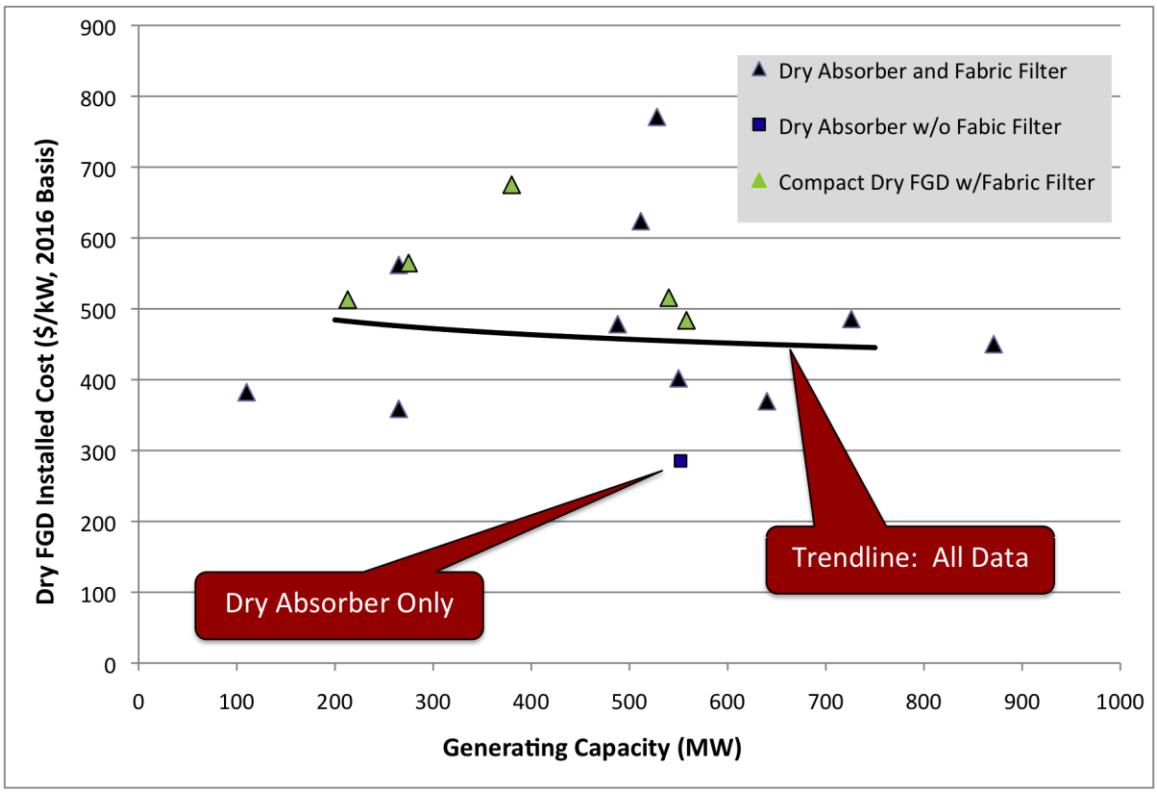

Figure 5-2. Dry FGD Process Equipment Cost (2016 Basis): Various Sources

The relative size of the process equipment for CDS and NID concepts is smaller than a conventional SDA: gas residence time in a CDS is typically 3-4 seconds and in an NID is 1 second, both significantly less than the 10-12 seconds that typify a conventional SDA.[14]

[14] *Circulating Dry Scrubbers: a New Wave in FGD?,* Power Engineering, November 1, 2011. Available at http://www.power-eng.com/articles/print/volume-115/issue-11/features/circulating-dry-scrubbers-a-new-wave-in-fgd.html

Reported costs for dry FGD concepts incurred between 2008 and 2017 range from a low of $250/kW to almost $800/kW, with an average cost approximating $450/kW for a 500 MW unit. The variability in cost for the 2008-2017 timeframe prevents deducing any trend in time.

The observations from the dry FGD installations are not parallel to those of wet FGD. Most notably:

Capital Cost Does Not Exhibit Strong Economies of Scale. Unlike wet FGD process equipment, the least cost installations ($/kW basis) are not typically associated with the largest generating capacity units. Figure 5-2 shows two of the lowest capital cost installations are among the smallest generating capacity.

The Capital Cost for "Compact" CDS/NID Dry FGD Equipment is Similar to Conventional SDA Equipment. Comparing capital cost for five "compact" dry FGD designs to ten conventional designs suggests there is no difference in these two design categories. This observation does not necessarily demonstrate that "compact" dry FGD equipment is equivalent in cost to conventional SDA equipment – it is possible an SDA process would require greater capital if retrofit to the same site. It is also possible the inherent higher gas pressure drop for CSD/NID technology (12-15 inches water gauge in some instances)[15] requires more costly gas handling equipment upgrade which offsets any savings in process equipment cost due to the compact size. Similar to the case of the Phase 1 wet FGD retrofits, the lack of experience in "compact" dry FGD design (compared to conventional SDA) may prompt designs for larger units to be based on replicating modules of subordinate components, not extracting maximum benefits of scale.

5.1.3. Dry Sorbent Injection (DSI) FGD

The injection of a dry alkali sorbent to remove moderate amounts of SO_2 (e.g. ~50%) from PRB fuels is deployed at some units as a low cost strategy to extract SO_2 reduction. Either sodium- or calcium-based sorbents can be deployed in an existing particulate collector. There are numerous challenges to deploying DSI for SO_2, although in general these can be manageable depending on the reagent and process conditions. These challenges include assuring the performance of the particulate removal system is not compromised, and managing the solid byproduct generated. For sodium-based reagent, some applications have encountered the sodium-prompted oxidation of NO to NO_2, generating a visible brown plume.

The cost for DSI for SO_2 control as reported to the EIA for units ranging from 250 to 1300 MW capacity averages $22/kW, with most installations ranging from $10 to $48/kW. The capital costs exhibit a modest economy-of-scale. For example, a DSI cost of $42/kW was cited for a 400 MW unit equipped with a fabric filter targeting 80% SO_2 removal,[16] while cost for a 1,300 MW unit equipped with an ESP were reported to the EIA as $36/kW.

[15] Ibid.

[16] Broglio, R, *A Low Cost Pollutant Control Solution: Installing a DSI Sytem at a Midwest Utility*, Power Engineering, September, 2014

5.2 FGD OPERATING COST

Operating costs are comprised of fixed components, whose content does not appreciably change with generator output, and variable components, whose content changes in proportion to generator output. Fixed and variable components of FGD operation are summarized as follows:

Fixed O&M. The fixed operating and maintenance (O&M) cost includes materials and operating staff, independent of how much the process is operated. The fixed O&M is estimated based on a fixed percent of the capital cost – and the size – of equipment.

Variable O&M. The variable O&M cost is mostly comprised of reagent consumption, solid waste byproduct and disposal, auxiliary power consumption, and make-up water.

Examples of operating cost incurred for wet and dry FGD systems are described subsequently.

5.2.1 Wet FGD

Table 5-1 presents an example of the fixed and variable operating cost components for a wet FGD system for a 500 MW unit, as recommended by Sargent & Lundy.[17] For example, fixed O&M labor is based on an additional 12-16 plant operators must be added to support wet FGD, depending on the size of the generating unit.

Table 5-1. Example Fixed, Variable O&M for Wet FGD (E. Bit Coal)

Operating Cost	Units	Value	Comment or Input
Fixed			
Additional Labor	$/kW-y	3.00	12 additional operators
Maintenance Labor, Material	$/kW-y	6.75	1.5% of capital cost
Administrative Labor	$/kW-y	0.17	
Total Fixed O&M	$/kW-y	9.92	
Variable			
Limestone Reagent	$/MWh	0.74	Limestone at $15/ton
Waste Disposal	$/MWh	2.47	Disposal at $30/ton
Make-up Water	$/MWh	0.08	Make-up water
Auxiliary Power	$/MWh	0.40	Based on 1.6% output at $25/MWh.
Total Variable O&M Cost	$/MWh	3.69	

Table 5-1 reports for a typical 500 MW plant, firing eastern bituminous coal with an SO_2 content of 5 lbs/MBtu (i.e., about 3% sulfur by weight), wet FGD requires fixed O&M of $9.92 /kW-y and variable O&M of $3.69/MWh. This wet FGD process is assumed to require 1.6% of the total plant generating capacity to operate. The auxiliary power consumption is assigned a cost penalty based on the wholesale energy price.

[17] *IPM Model – Revisions to Cost and Performance for APC Technologies: Wet FGD Cost Development Methodology Final,* prepared by Sargent & Lundy, August 2010, Project 12301-007, for Perrin Quarles Associates, Inc.

5.2.2 Dry FGD

Table 5-2 presents an example of the fixed and variable operating cost components for a 500 MW dry FGD system, as recommended by Sargent & Lundy[18], including a pulse-jet baghouse thus comprising a combined particulate/SO_2 removal system.

Table 5-2 reports that for a typical 500 MW plant, firing low sulfur eastern bituminous coal (0.4% sulfur content), dry FGD with a pulse-jet fabric filter requires fixed O&M of $8.89/kW-yr and variable O&M of $1.54/MWh. The dry FGD process is assumed to require 1.35% of the plant generating capacity while the associated fabric filter element consumes an additional 0.4%.[19] The auxiliary power consumption is assigned a cost penalty based on the wholesale energy price.

Table 5-2. Example Fixed, Variable Operation and Maintenance for Dry FGD/Fabric Filter

Operating Cost	Units	Value	Comment or Input
Fixed			
Additional Labor	$/kW-y	2.00	8 additional operators
Maintenance Labor, Material	$/kW-y	6.75	Per $450/kW capital
Administrative Labor	$/kW-y	0.14	
Total Fixed	$/kW-y	8.89	
Variable			
Lime Reagent	$/MWh	0.60	Lime at $95/ton
Waste Disposal	$/MWh	0.43	Disposal at $30/ton
Filter/Cage Replacement	$/MWh	0.14	Filter bags @$90 each; cages @ $50/ each
Make-up Water	$/MWh	0.03	Make-up water
Auxiliary Power	$/MWh		
SDA		0.34	1.35% of MW at $25/MWh
Fabric Filter		0.10	0.40% of MW at $25/MWh
Total Variable O&M Cost	$/MWh	1.54	

5.3 LEVELIZED REMOVAL COST PER TON

The total cost of deploying wet or dry FGD will include the capital charge and the sum of fixed and variable operating charges. For a 500 MW power plant, Figure 5-1 suggests wet FGD capital cost for units installed in 2012 or thereafter is about $450/kW, requiring a $225 M capital investment. The annual charge for this capital – based on a 15-year recovery period and a capital

[18] *IPM Model – Revisions to Cost and Performance for APC Technologies: SDA FGD Cost Development Methodology Final,* prepared by Sargent & Lundy, August 2010, Project 12301-007, for Perrin Quarles Associates, Inc. Hereafter S&L IPM SDA 2010 Report. Also, *Model – Revisions to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology Final,* prepared by Sargent & Lundy, March 2011, Project 12301-009, for Systems Research and Applications Corporation, Hereafter S&L IPM Particulate Control 2011 Report.
[19] Ibid.

cost recovery factor derived from a DOE NETL cost assessment methodology[20] – is 0.125, resulting in an annual payment of $28.13 M. In addition to this annual charge for capital, wet FGD operating costs will be incurred as exemplified by Table 5-1 for eastern bituminous coal with 5 lbs SO_2/MBtu sulfur content. Operating cost for lower sulfur coals are analogous to Table 5-2 but are lower in approximate proportion to sulfur content.

Figure 5-3 presents the levelized cost of SO_2 removal for wet FGD process equipment, cast in terms of cost per ton of SO_2 removed. Figure 5-3 presents the cost as a function of the capital requirement for process equipment and for a typical high sulfur eastern bituminous coal, and low sulfur coal such as PRB, operating at an 85% capacity factor.

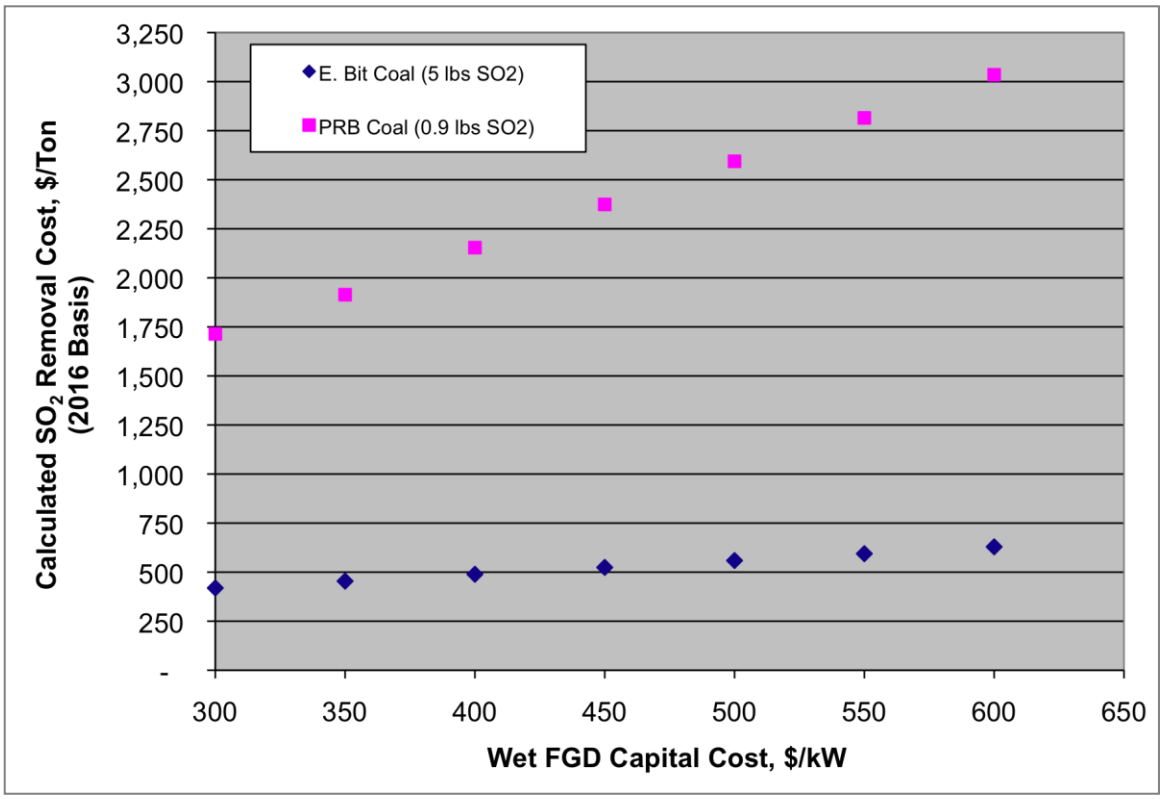

Figure 5-3. Calculated SO_2 Removal Cost per Ton for E. Bit, PRB Coal: Wet FGD Retrofit to 500 MW Unit

[20] *Quality Guidelines For Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance*, DOE/NETL-2011/1455, April 2011. See Exhibit 4-1. A capital recovery factor of 0.125 represents average for "Low Risk" project and 3-year expenditure period for financing by an IOU (Exhibit 4-6) and IPP (Exhibit 4-7).

SECTION 6

SELECTIVE CATALYTIC REDUCTION COST

This section presents capital and operating costs for SCR NO_x control, reflecting units installed from 1994 through 2017.

6.1 SCR CAPITAL COST

Figure 6-1 summarizes capital cost for four deployment periods, starting as early as 1994 and projected through 2017. For each of the four deployment periods, the curves represent unit capital cost ($/kW) versus generating capacity.

Figure 6-1 represents cost data from approximately 70 SCR installations. The costs are reported on a 2016 dollar basis, and include staff engineering, owners' engineering, and financing charges (AFUDC). As with FGD process equipment, it should be cautioned not all cost data represent comparable cases – there are differences in inlet NO_x, NO_x removal, fuel type, catalytic reactor design and arrangement, number of catalyst layers, reagent type, and balance-of-plant equipment. The design premise for many recent SCR installations considered their role in prompting Hg removal for the MATS. These design decisions (a) specify the use of catalyst that in addition to reducing NOx will prompt the oxidation of Hg, contributing to capture via wet FGD, and (b) minimize the interference of catalyst-generated sulfur trioxide (SO_3) on Hg absorption by activated carbon. The site-to-site differences in the costs shown in Figure 6-1 are believed an accurate reflection of the industry average.

Figure 6-1 presents four curves reflecting cost incurred for the years (a) preceding 2000, reflecting the earliest projects (Curve A), (b) 2000-2007, reflecting the class of units installed prior to broad Phase 1 CSAPR compliance (Curve B), (c) 2008-2011, reflecting units installed during the height of Phase 1 CSAPR compliance (Curve C), and (d) 2012-2017, reflecting units recently installed or presently under construction (Curve D). With the exception of Curve D, individual data points are omitted for clarity.

Curve A represents capital cost for five units retrofit with SCR prior to 2000 to comply with either a state regulation, the 1997 SIP-Call, or Phase 2 of the Acid Rain Program for certain "Group 2" boilers. Curve A shows the capital cost ($/kW basis) for the earliest units retrofit with SCR did not change with generating capacity – the average cost was about $100/kW.

Curve B represents capital cost for units starting commercial operation from 2000 through 2007. Curve B is derived from 32 units, most of which were deployed to meet Phase 1 CAIR (i.e., the CSAPR predecessor, and relevant mandate at the time) limits for NO_x; although some retrofits were also to satisfy consent decrees regarding alleged New Source Review (NSR) violations. Curve B data exhibit a modest relationship between generating capacity and capital cost, showing higher generating capacity leads to slightly lower cost per unit basis ($/kW basis).

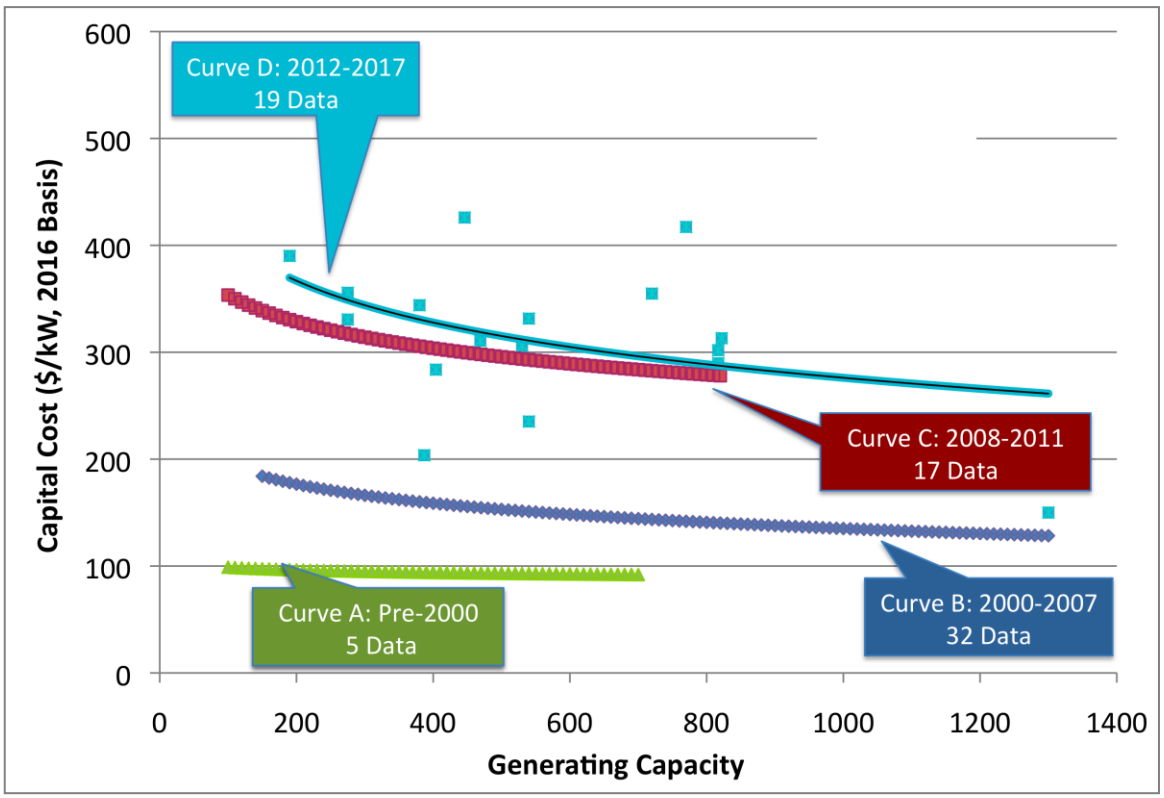

Figure 6-1. Capital Cost of SCR Process Equipment vs. Generating Capacity (2016 Basis): Four Time Periods

Curve C represents the capital cost for 17 units starting commercial service between 2008 and 2011, with most retrofits installed to satisfy Phase 1 CAIR mandates. Curve D reflects cost for units retrofit with SCR starting in 2012 and continuing through 2017.

The data in Figure 6-1 suggest the following:

Capital Cost Has Escalated with Time. Capital cost required for SCR has escalated since the earliest installations prior to 2000. For a 500 MW unit, the average capital cost incurred for SCR retrofit between 2000 and 2008 increased by $75/kW compared to those installed prior to 2000. The capital required for this same 500 MW unit increased by perhaps another $125/kW for units installed in 2008-2011; and modestly by approximately $50/kW for units installed in 2012-2017. The escalation in cost is clear despite the variability in the data.

Capital Cost Exhibits Significant Economies of Scale. Lower capital cost per unit output ($/kW) is observed at higher generating capacities – materially so in many cases. An exception in this trend is noted for the units installed prior to 2000 to meet Phase 1 of the 1997 SIP-Call. Similar to the case of wet FGD, early data do not exhibit a strong economy-of-scale – perhaps a consequence of higher design margins to account for uncertainty in the largest units, and limited experience.

The consistent, stepwise escalation in SCR cost – when considered in terms of a 500 MW unit – translates into about $11/kW per year over a 20-year period (i.e., 1995 through 2017).

As noted, the most recent generation of SCR process designs (Curve D) considered their role on Hg capture, and minimizing the production of SO_3. The SCR capital cost cited in Figure 6-1 does not include proactive SO_3 mitigation steps, such as providing DSI to capture SO_3. Such costs are not necessarily small – the cost for DSI reported to the EIA for units from 250 to 1,300 MW generating capacity ranged from $5 to $50/kW, averaging $24/kW. Further, it is possible the cost for SCR was affected by the use of catalyst with lower SO_2-to-SO_3 oxidation which – depending on the supplier – could compromise activity for NOx removal.

6.2 OPERATING COST

Operating costs for SCR processes consist mostly of replacement catalyst and ammonia-based reagent. The cost for each of these consumables has changed in the last 10 years. In the early phases of SCR operation the largest operating cost component was replacing catalyst, followed by supplying reagent. In the last ten years, a decrease in catalyst cost and increase in ammonia prices have inverted this relationship – for most units reagent supply now dominates operating cost. The unit cost of catalyst has been mitigated by many factors, including the evolution of regenerated catalyst. The fixed operating and maintenance costs are generally small compared to these two variable components.

Factors affecting catalyst and reagent supply and reagent cost are discussed subsequently.

6.2.1 SCR Catalyst

The unit cost of catalyst has decreased significantly since the early 1980s. Two factors have provided a downward pressure on prices: an increase in world-wide production capability, and the ability to regenerate or rejuvenate catalyst for a cost equivalent to approximately 50% of cost for new product. Catalyst prices dropped to near $4,000/m^3 in 2005, but have slowly increased with additional demand created by the retrofit of SCR reactors. Further, the need for replacement catalyst increased as seasonal NO_x emissions limits evolved to annual requirements, requiring year-round operation in starting in 2009.

Catalyst prices at present remain in the approximate range of $5,000 per cubic meter ($/m^3), although there are reports of cost below $5,000/m^3 depending on market conditions.

6.2.2 Reagent

SCR operators can choose from four types of ammonia-based reagent: anhydrous ammonia, aqueous ammonia of 19.5% NH_3 content or 29% NH_3 content, or urea. The cost of reagent varies with the form and chemical compound in which the NH_3 is delivered. Specifically, the cost to deliver a mole of NH_3 is the least for anhydrous ammonia, and increases with aqueous ammonia (due to the cost of providing the carrier media of purified water). The cost of providing a usable mole of NH_3 can be higher with urea, but varies with processing costs and world-market demand. Regardless of reagent price, the least cost approach to deliver reagent for SCR will depend on numerous system factors – many related to safety and auxiliary power to operate the supply equipment. Notably, the risk management cost – that attributed to preventing spills – for anhydrous ammonia can be a significant fraction of total reagent system costs. In contrast, the

risk management cost for urea-based systems is negligible. Consequently, both aqueous ammonia and urea can comprise the least cost approach depending on the conditions at the site. For the purposes of this discussion, anhydrous ammonia is discussed, recognizing that alternative reagent forms are equally viable.

Historically, the price of anhydrous ammonia is largely determined by the cost of natural gas feedstock. Figure 6-2 compares the price of anhydrous ammonia ($/ton) to that of natural gas ($/1000 cubic feet), as compiled by the University of Illinois at Urbana-Champaign.[21] Natural gas and anhydrous ammonia prices have been coupled since about 1984, but this relationship broke down in about 2006 as natural gas prices decreased but ammonia remains high – with the price of the latter driven by demand in agricultural markets.[22] Anhydrous ammonia prices exceeding $800 /ton were witnessed in 2014 but such prices have relaxed to about $600/ton since then.

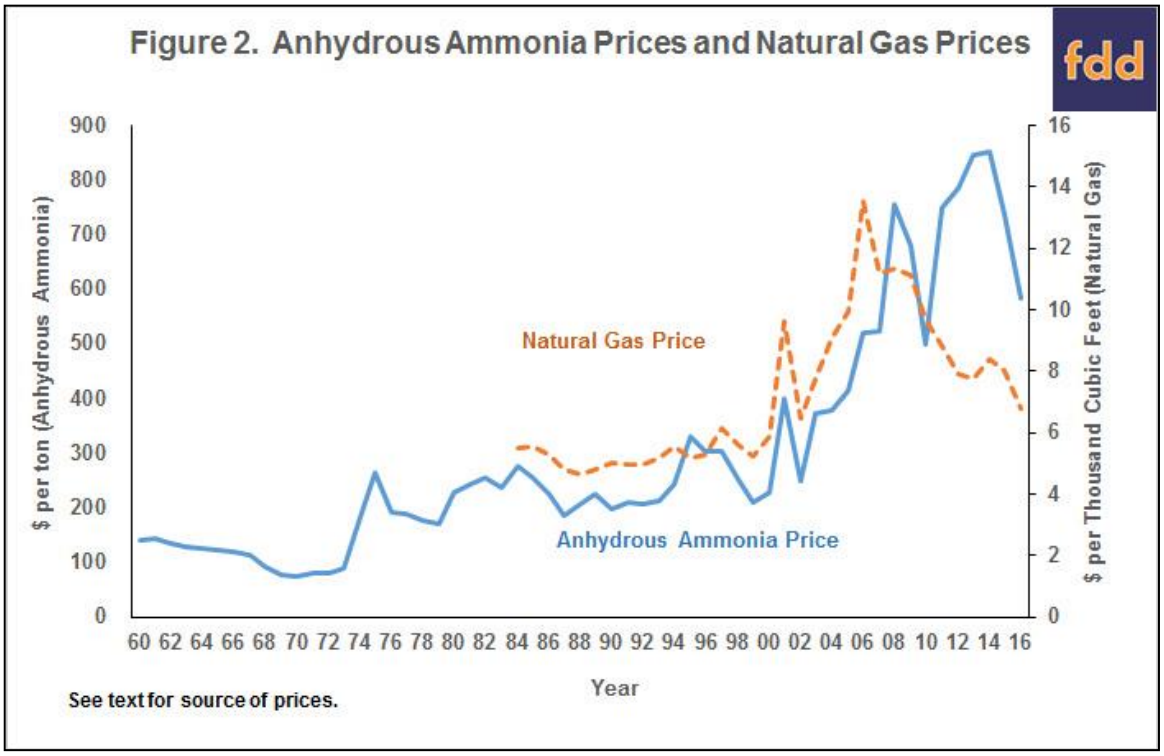

Figure 6-2. Midwestern Anhydrous Ammonia Prices: 2000- 2017[23]

6.2.3 Example Operating Cost

The operating and maintenance cost for an SCR process can be developed (for a 500 MW unit) based on assumptions in Table 6-1. These are:

[21] http://farmdocdaily.illinois.edu/2016/06/anhydrous-ammonia-corn-and-natural-gas-prices.html

[22] http://farmdocdaily.illinois.edu/2011/10/relationship-between-anhydrous-1.html

[23] Source: Anhydrous Ammonia, Corn, and Nautual Gas Prices Over time, farmdocDaily, June 14, 2016. Available at: http://farmdocdaily.illinois.edu/2016/06/anhydrous-ammonia-corn-and-natural-gas-prices.html

Fixed O&M. Spare parts and support for miscellaneous duties that must be executed regardless of unit operation. Experience suggests this cost can be $200,000 annually.

Catalyst Supply. Catalyst supply cost is determined by periodic purchases from which an annual charge can be calculated. The periodic purchases add catalyst to the spare layer or replace existing catalyst. For an SCR reactor with a 2+1 catalyst arrangement, designed with an initial space velocity of 3,200 l/h and a 16,000 operating hour guarantee, the purchase of one layer every 16,000-20,000 operating hours may be required. Operating experience suggests this replacement schedule for many units is a best-case scenario, and more frequent catalyst changeout needed.

Reagent Cost. The purchase of anhydrous ammonia for 87% NO_x removal from 0.35 lb/MBtu, at 85% capacity factor, defines the reagent cost. A delivered price of $700/ton is assumed.

Table 6-1. Key SCR Operating Cost Components: 500 MW Reference Plant

Operating Cost	Units	Value	Comment or Input
Fixed			
Consumable materials, Maintenance staff	$/kW-y	0.40	Percent of process capital ($200,000 for 500 MW)
Operators/engineering	$/kW-y	0.79	50% of one operator, one engineer
Total Fixed O&M	$/kW-y	1.19	
Variable			
Ammonia reagent	$/MWh	0.39	Anhydrous ammonia at $700/ton
Catalyst replacement (annual equivalent)	$/MWh	0.16	Acquire/replace one layer at 16,000 hr operating intervals
Fuel cost (auxiliary steam)	$/MWh	0.03	Catalyst sootblowers
Auxiliary power	$/MWh	0.08	Based on 5” w.g. @ energy price of $25/MWh
Total Variable Cost	$/MWh	0.65	

Auxiliary Power. Auxiliary power for an additional 5 inch water gauge (w.g.) flue gas pressure drop is assumed – 4 inch w.g. for the process flange-to-flange, and an additional 1 inch w.g. across the air heater.

Catalyst Cleaning. Sootblower consumption of 0.2% of the plant steam output is assumed; this steam is assigned a cost of $1/MBtu. Many new SCR installations employ acoustic horns for cleaning, which require auxiliary power that constitutes approximately the same cost.

Operating Staff. One additional operator dedicated to 50% duty is assumed to be required to maintain the above components. Also, a part time (50%) engineer to assess operation and evaluate data is assumed. The need to account for additional staff due for SCR operation is highly variable; some owners report additional operating or engineering staff is not required for these purposes.

Table 6-1 lists fixed O&M, additional labor for operating staff, steam for sootblowers, reagent for NO_x reduction, auxiliary power and an annualized charge for catalyst supply. Of note is that for the reference case presented, the annual equivalent charge for replacement catalyst is about 1/3 of the annual charge for anhydrous ammonia – an outcome unthinkable in the last decade. Clearly, the high cost of reagent – prompted by agriculture demand for fertilizer and fertilizer feedstock – is a key factor determining the NO_x control cost per ton.

6.2.4 Levelized Removal Cost Per Ton

The levelized cost of NO_x control, expressed in terms of cost per ton of NO_x removed, is determined from operating cost and capital recovery charges, and normalized by the amount of NO_x removed.

The 500 MW reference plant described in Section 5 is used as the basis for this analysis. The boiler emission rate for this reference unit, firing bituminous coal, is assumed to be 0.35 lb NO_x/MBtu, and require control to a stack outlet value of 0.05 lb/MBtu (86% reduction). Results are also shown for a PRB-fired case, characterized by a boiler emission rate of 0.20 lb/MBtu and requiring 75% NO_x reduction, and operating at an 85% capacity factor.

The total charges can be developed for a 500 MW unit retrofit with SCR in 2016 or thereafter. Figure 6-1 suggests a 500 MW plant adopting SCR will incur a capital charge of approximately $325/kW, thus requiring $163 M. Based on a 15-year life and using the capital cost recovery of 0.125, an annual charge for capital is estimated to be approximately $21.9 M.

Figure 6-3 presents the levelized cost of NO_x removal, in terms of cost incurred per ton of NO_x removed, as a function of SCR capital cost. The results are shown for both an eastern bituminous coal and PRB.

In the present utility operating environment, it is likely more important to view SCR retrofit cost in terms of compromising the economic position of a unit in a competitive power market. A comparison of SCR variable operating and maintenance costs and the total carrying costs (e.g., capital recovery, fixed O&M, and variable O&M) for a 500 MW unit to the wholesale power price observed in 2016 is presented in Section 8.

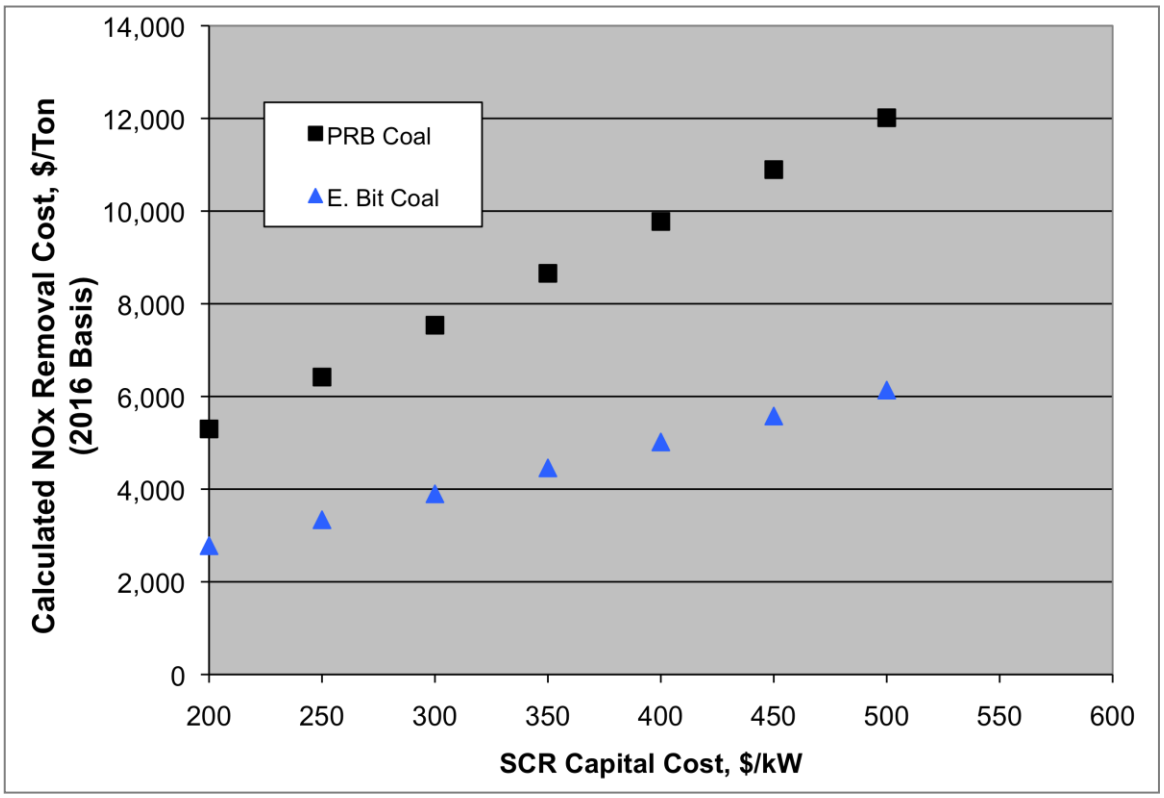

Figure 6-3: Calculated SCR NO_x Control Cost per Ton of NO_x Removed: 500 MW Reference Plant, E. Bit and PRB Coal

SECTION 7

FABRIC FILTER CONTROL TECHNOLOGY COSTS

Section 7 presents capital and operating costs for fabric filter particulate controls, commonly referred to as "baghouses," retrofit to existing units. The reasons to retrofit fabric filter equipment are numerous. These reasons include, most notably, (a) as a key component of a dry FGD process equipment, and (b) to comply with the Mercury and Air Toxics Standards (MATS) rule.

The retrofit of control technology for MATS typically includes equipment for receiving, storage, and injection of activated carbon into the gas stream. The cost cited in this section for fabric filters does not include a charge for activated carbon injection (ACI). Based on cost data submitted to the EIA, the capital required for ACI injection apparatus for units ranging from 250 to 1,300 MW of capacity ranged from $3 to $18/kW, and averaged $11/kW. One observer noted that a 600 MW unit required 25-$42/kW for an installation with sophisticated instrumentation that improved reliability and lowered long-term operating cost.

Similar to SCR and FGD, fabric filter control technology has evolved in recent decades. Figure 7-1 presents a perspective view of a fabric filter with the inset showing how the filter bags are arranged and the gas flow pattern.

Fabric filter controls can employ thousands of individual filters – 15,000 – 22,000 for a large plant, arranged in perhaps 8 to 15 individual compartments.[24] These filters are configured as "bags" and are oriented so particulate-laden flue gas enters from the periphery (outside) of the filter, with flue gas flowing radially inward. Particulate matter is removed on the fabric. The bags are periodically cleaned of the collected ash by any of several methods; the present state-of-art approach is a cleaning "pulse" of high-pressure air that dislodges the ash. Fabric filter particulate collectors that employ this method of cleaning are referred to as the "pulse-jet" design. The cleaning cycle is typically intervals of several hours.

Similar to FGD, there are numerous variants of fabric filter design that affect capital cost. Perhaps the most important is the air/cloth ratio (gas or "air" flow treated normalized by total cleaning surface area), although the composition and height of the filter bags and the arrangement of compartments are important. Fabric filter technology has evolved from the early generation designs using "reverse-gas cleaning" with air/cloth ratio of nominally 3 ft/min, to the more recent "pulse-jet" designs with an air/cloth ratio of approximately 6 ft/min.

[24] Brinkley, R.B. et. al., *WPCA-Duke Energy Pulse-Jet Fbric Filter Training*, Presentation to the Worldwide Pollution Control Association, October 12-13, 2011.

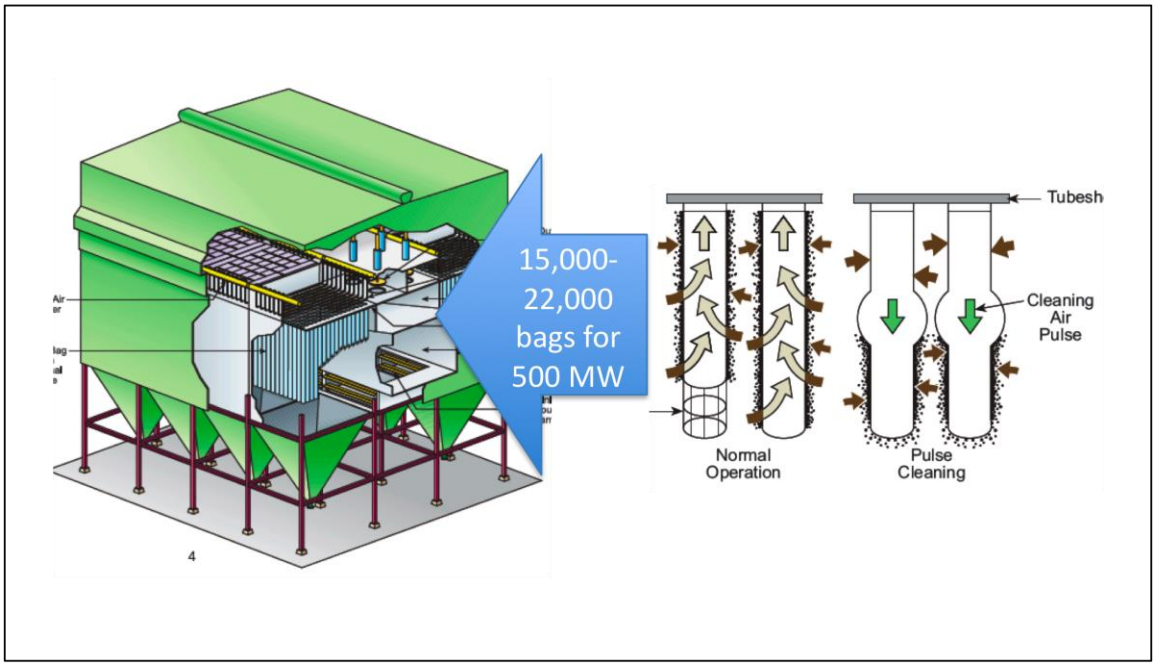

Figure 7-1. Fabric Filter Particulate Control Device and Detail of Filter Material[25]

7.1 FABRIC FILTER CAPITAL COST

Figure 7-2 presents fabric filter capital cost versus generating capacity reported for 35 units installed over three time periods – 2009 and earlier; 2010-2013; and 2013-2017. The capital cost data reported in Figure 7-2 describes a complete scope of work, including ancillary equipment such as flue gas fans and ductwork, indirect charges, and AFUDC, escalated into end-of-year 2016-dollar basis.

The three time periods are selected to identify a possible cost trend in anticipation of the MATS compliance date of May 2015 (or 2016 if the unit receives an extension). Retrofits during the first time period – 2009 and earlier – are not MATS related as the legislation had yet to be proposed or finalized. Reported fabric filter retrofit costs for this first time period vary by a factor of four. Several of the fabric filters retrofit for slightly more than $100/kW over this time period benefited from economies-of-scale with installation of other equipment (e.g., SCR and wet FGD), or utilizing an existing hot-side ESP casing.

Capital costs reported for the second time period of 2010- 2012 are within the range exhibited by the pre-2009 units but feature less variability. Most of the lowest cost units ($150-200/kW) installed over this period involved multiple projects at one site, and thus exploited economies of scale in design and installation.

[25] Source: Adopted from B&W Brochure, *Pulse-Jet Fabric Filters,* available at http://babcock.com/products/environmental_equipment/particulate_and_dust_control.html

The highest fabric filter capital costs are observed for units installed in the most recent 2013-2017 time period. Most of these units were likely retrofit to support MATS mandates and were required to be operational in May of 2015 or 2016. The costs for units reported for this time period are the highest observed.

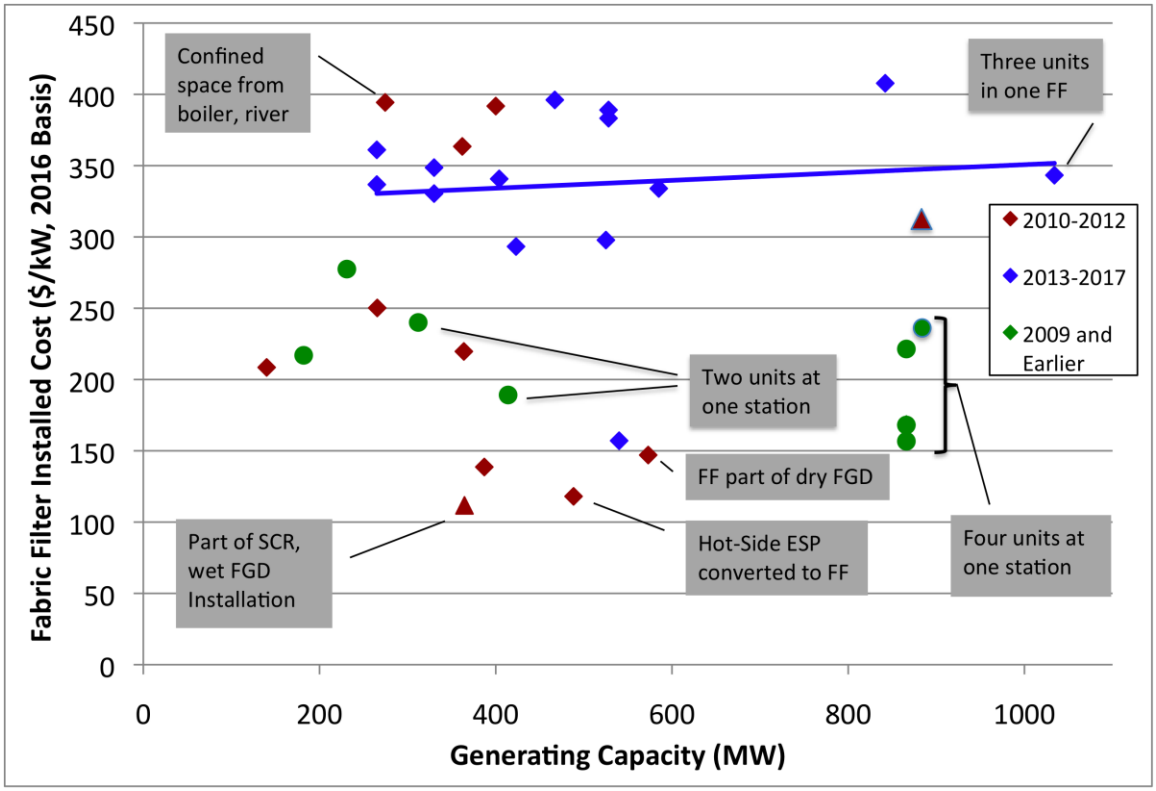

Figure 7-2 Fabric Filter Capital Cost (2016 Basis) vs. Generating Capacity

Most notably, there is no clear relationship between capital cost and generating capacity for any of the three time periods. The capital cost to retrofit fabric filters, similar to FGD and SCR, depends on numerous site-specific factors. These include (a) available space for ductwork, (b) clear access by cranes and construction equipment, (c) the cost for process equipment (air/cloth ratio, bag height, number of compartments, etc.), and (d) construction labor. Almost without exception, the retrofit of a fabric filter will required upgrading the gas handling system, and how this cost is reported and apportioned over other components can vary between projects.

Several example sites are discussed, categorized in terms of site access as either "good" or "limited".

7.1.1 Good Site Access

Two generating sites with "good" access – Dairyland Power Madgett Unit 1 and Dynegy Vermillion Units 1 and 2 – are described. Sites designated with "good" access typically incurred a fabric filter capital cost of less than $200/kW.

Figure 7-3 depicts the site layout for Dairyland Madgett Unit 1. The fabric filter, denoted within the blue circle, processes flue gas from the boilerhouse after passing through the SCR reactor. The gas flow path is shown exiting the boilerhouse, passing through and exiting the SCR reactor (red arrows). The flue gas then passes through the air heater (red circle) and continues into the fabric filter (blue circle). The flue gas exits the fabric filter and enters the stack along the path indicated by the green arrows.

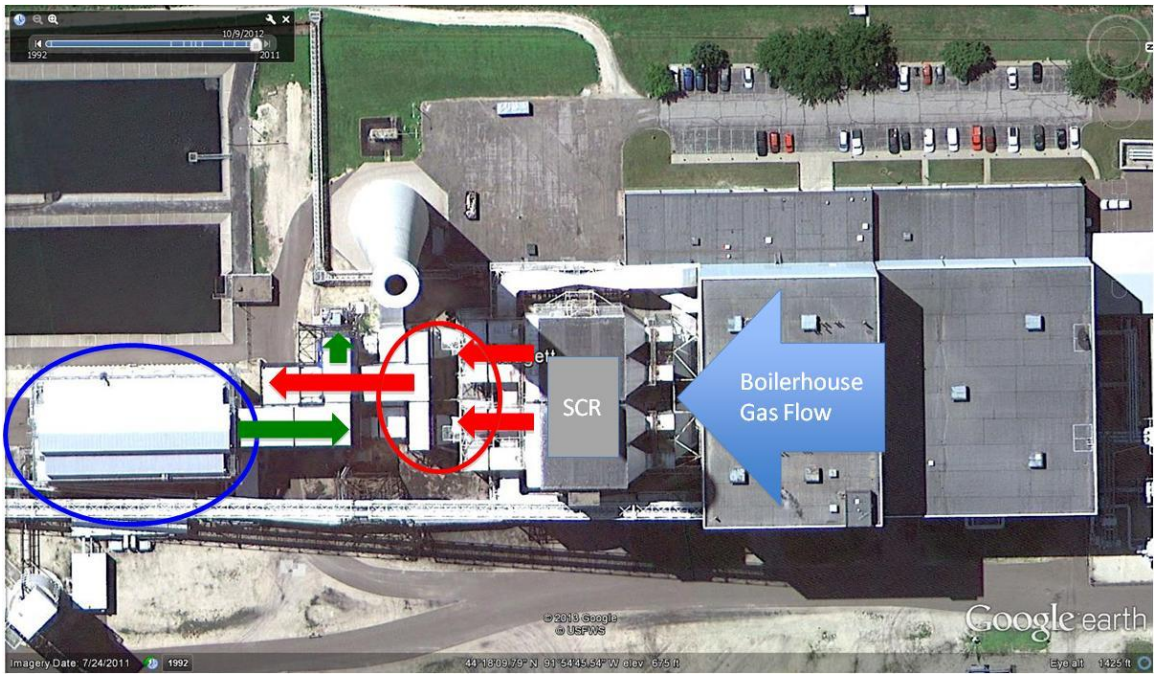

Figure 7-3. Dairyland Power Madgett Unit 1: Fabric Filter Installation

Figure 7-4 presents the site layout for Dynegy Vermilion Units 1 and 2. The flue gas from each unit exits the boilerhouse and passes through the air heater (red circle), then enters a common duct leading to the fabric filter (blue circle). The flue gas from the fabric filter returns to the stack (ductwork indicated by the green arrows).

7.1.2 Limited Site Access

Among higher cost fabric filters (from $200-400/kW) are several examples representing sites where construction access is severely inhibited. An example station discussed for this category is Alabama Power's Gorgas Station.

Figure 7-5 depicts the Gorgas Station identifying one of the baghouses located on this multi-unit site. Figure 7-5 shows gas flows from the boiler house and is directed to an adjacent location featuring a baghouse, new stack, and wet FGD process. The Gorgas site was able to accommodate fabric filters, but only at the cost of considerable extended ductwork and gas handling equipment upgrade. Figure 7-5 shows the additional ductwork and gas handling fans that are necessary to direct gas flow to the wet FGD and stack.

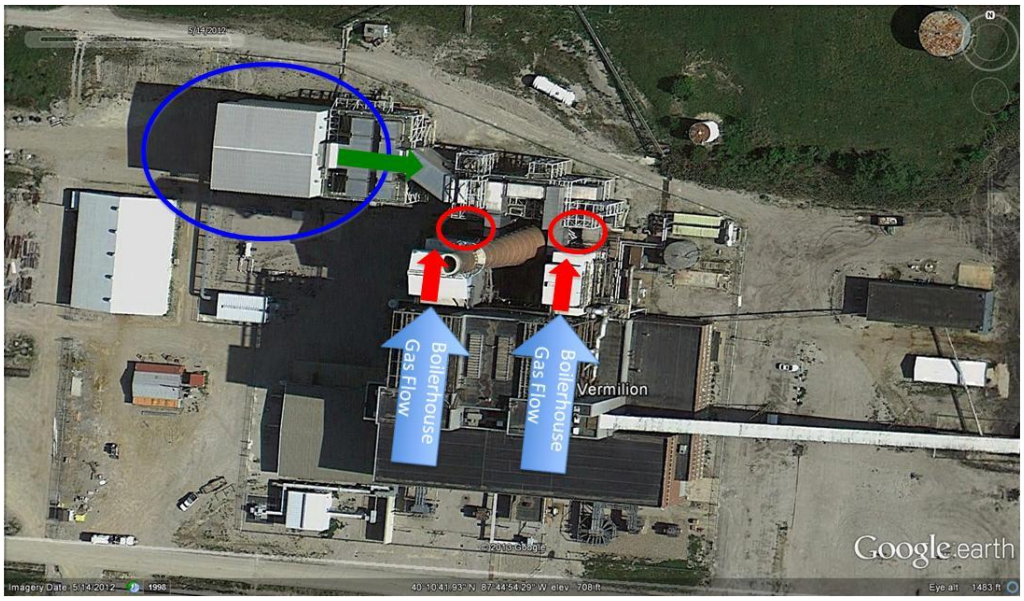

Figure 7-4. Dynegy Vermilion Units 1 and 2: Fabric Filter Installation

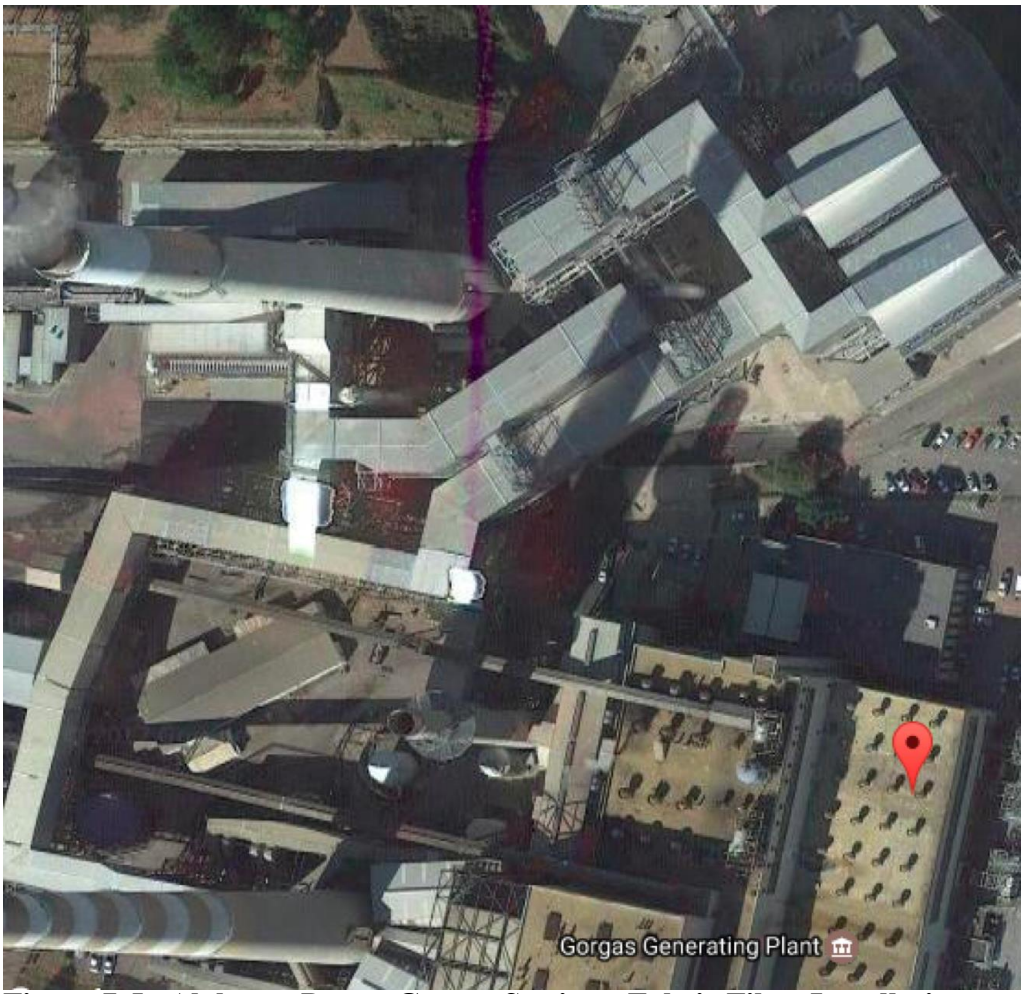

Figure 7-5. Alabama Power Gorgas Station: Fabric Filter Installation

7.2 EXAMPLE OPERATING COST

The operating and maintenance cost for a fabric filter for particulate removal can be developed (for a hypothetical 500 MW unit), based on assumptions in Table 7-1 that define the conditions of operation in terms of fixed O&M, variable O&M, and capital cost and recovery. The reference 500 MW unit is assumed to deploy a fabric filter for a capital cost of $325/kW.

7.2.1 Fixed O&M

Fixed operating and maintenance (O&M) expenditures consist of spare parts and services for miscellaneous duties – independent of how much the fabric filter is operating. This cost is assumed to be equivalent to 0.25% of process capital.

Maintenance staff needs are highly variable – some owners report adding operating staff while others require the duties to be absorbed by existing staff. This example case assumed an intermediate position – one operator at 50% duty is assumed for general maintenance and a part-time (50%) engineer to assess operation and evaluate data.

Table 7-1. Key Fabric Filter Operating Cost Components: 500 MW Reference Plant ($325/kW Capital, 2016 Dollar Basis)

Cost Component	Basis	Annual Cost for 500 MW ($/yr, at 85% Capacity Factor))	Annual Cost (mills/kWh)
Operations			
Fixed O&M	0.25% of Process Capital	405,000	0.109
Labor	Operators/Part-time Engineer	375,000	0.101
	Total Fixed O&M	780,000	0.210
Variable O&M			
Replacement Filter Materials	Based on individual filter cost of $90 each, and support cage cost of $50/each	530,000	0.142
Auxiliary Power	0.60% unit output @ $20/MWh	447,000	0.120
	Total Variable O&M	977,000	0.262
Total Operations		1,757,000	0.472
Capital			
Capital Requirement	Based on unit cost of $325/kW, and capital recovery factor of 0.125	20,312,000	5.46
Total: Levelized Operations and Capital		22,069,500	5.93

7.2.2. Variable O&M.

Replacement filter bags and cages, and auxiliary power are key components to variable O&M.

Replacement Bags and Cages Supply. The 500 MW reference unit is assumed to contain 14,000 individual filter bags, which (with support cages) are assumed replaced at 3-year intervals. Consistent with assumptions developed by Sargent & Lundy for EPA, the replacement bags and support cages are assumed to cost $90 and $50 each, respectively.[26] The annual cost to replace bags and cages is developed assuming 1/3 of the total filter bag and cage inventory is replaced annually.

Auxiliary Power. The auxiliary power demand depends on the design of the fabric filter, most notably the air/cloth ratio. Typically, the fabric filter pulse-jet design that uses high air/cloth ratios (~6 ft/s) will incur a greater gas pressure drop than designs based on conventional reverse-gas or shake-deflate cleaning. A typical pulse-jet unit with an air/cloth ratio of 6 ft/s will incur an additional 6 inch water gauge (w.g.) gas pressure drop. For the present analysis, an additional auxiliary power of 8-inch w.g. gas pressure drop is assumed – comprised of 6 inch w.g. for the fabric filter and an additional 2 inch w.g. for ductwork. This pressure drop will consume 0.60% of the plant gross generating capacity.

Table 7-1 summarizes the operating cost components for a fabric filter retrofit to the 500 MW reference unit. The cost analysis includes fixed O&M, labor required for operating staff, and the variable O&M for replacement filters and auxiliary power.

Table 7-1 summarizes fabric filter operating cost for the purpose of particulate removal (e.g. excluding the cost for activated carbon or other sorbents for Hg removal). As noted, many fabric filters are believed to have been retrofit to support Hg removal, providing a reaction environment for activated carbon or other sorbents. The cost for these sorbents is significant. For example, the cost for halogenated activated carbon to achieve 90% Hg removal within the fabric filter of the 500 MW unit depicted in Table 7-1 can exceed $900,000 per year (based on a sorbent addition rate of 1 lb per million ACFM of gas flow, delivered sorbent cost of $1.00 per lb).

7.3 LEVELIZED COST

Table 7-1 summarizes levelized cost of deploying fabric filter control technology based on capital recovery and operating cost.

Levelized costs are developed for the 500 MW reference plant described in Section 5, retrofit with a fabric filter in 2017. Table 7-1 reflects a fabric filter capital charge of approximately $325/kW, thus requiring $162.5 M. Based on a 15 year life and using the capital cost recovery factor 0.125, the annual charge for capital is estimated to be $20.3 M.

[26] *IPM Model – Revisions to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology Final,* prepared by Sargent & Lundy, March 2011, Project 12301-009, for Systems Research and Applications Corporation.

The sum of all operating costs and the annual charge for capital recovery is $1.76 and $20.3 M, totaling $22.1 M. Levelized cost per production basis to deploy a fabric filter for the 500 MW reference unit is 5.93 mills/kWh.

SECTION 8

CONCLUSIONS

The rate escalation in cost to acquire and retrofit FGD has moderated from that observed since 2011, but it continues to escalate for SCR process equipment and fabric filters.

Several opposing cost pressures are responsible. Contributing to the moderation in cost is reduced demand for raw material and finished steel products, compared to the peak demand that was observed from 2008 to 2011. Price indices of key inputs such as steel, iron ore, and non-ferrous metals are below the highs experienced in the 2008-2011 time period, but remain well above the indices of earlier periods.

Skilled labor rates continue to escalate. The specialty labor pool for which shortages in 2007 and 2008 limited the rate of project completion remains in strong demand, thus labor rates continue to modestly escalate (1-2% annually). The productivity in deploying this labor pool for future projects will likely be higher due to the improved skill and experience of the available worker.

A third factor contributing to the escalating SCR and fabric filter costs is the increasing complexity of the site to which the equipment is installed. In general, the sites most recently retrofit are typically the most complex – with this complexity likely being the key reason the particular station was not retrofit earlier.

Regarding FGD, since the year 2000 almost 150 GW of coal-fired capacity have been retrofit with either wet or dry-based processes. For wet FGD installed from 2012 to 2016 the rate of capital cost escalation has moderated compared to units retrofit between 2008 and 2011. A wet FGD process for a 500 MW plant will require a capital charge of approximately $450/kW, on average. A dry FGD process will require about the same capital cost on average – approximately $450/kW for a 500 MW unit – but this cost includes a fabric filter for particulate matter control.

Regarding SCR NO_x control, since the year 2000 approximately 140 GW of coal-fired capacity have been retrofit. The rate of cost escalation continues, with the average capital cost of retrofitting SCR to a 500 MW plant approximating $325/kW.

Regarding fabric filters, since the year 2000 approximately 30 GW of coal-fired capacity have been retrofit. Similar to FGD and SCR process equipment, capital cost to retrofit fabric filters varies widely, as defined by site conditions and the year of installation. The most recent group of fabric filters that were installed to support meeting the MATS mandates exhibit as a group the highest cost. For this group the average cost to retrofit a fabric filter to a 500 MW unit is approximately $325/kW.

Figure 8-1 provides insight as to the total cost of owning and operations for key emission control technologies, relative to the range of wholesale power price recently observed. Figure 8-1 depicts

the range of wholesale power prices observed by the EIA in 2016 at five key trading hubs.[27] Figure 8-1 also reports the cost of owning and operating wet FGD and SCR process equipment for a 500 MW reference plant, firing eastern bituminous or PRB-fired coal. For these control technologies the total cost of owning and operations – accounting for capital repayment, fixed operating cost, and variable operating cost – is shown for both wet FGD and SCR applied to a 500 MW unit firing either eastern bituminous or PRB coal, and operating at an 85% capacity factor. Figure 8-1 also shows for comparison cost of fuel for power generation for a natural gas combined cycle unit or coal-fired steam boiler. The fuel cost is reported in terms of $/MWh assuming typical heat rates for these generating assets.

Figure 8-1 presents the cost for deploying wet FGD alone, SCR alone, and the sum of costs for both wet FGD and SCR. These costs are presented for both eastern bituminous and PRB-fired units.

Figure 8-1 shows the cost for owning and operating wet FGD applied to a 500 MW unit firing either eastern bituminous or PRB fuel ranges between $11-13/MWh; SCR applied to the same unit incurs a cost of approximately $6/MWh. A unit equipped with both wet FGD and SCR – based on Figure 2-7 representing more than 140 GW of capacity – will incur a total cost of ownership and operation approximating $17-19/MWh. Figure 8-1 shows the cost to deploy both wet FGD and SCR on an average 500 MW unit is approximately equal to the fuel cost for a coal-fired steam boiler (at $1.50/MBtu) and approaches the fuel cost for a natural gas fired combined cycle unit (at $3/MBtu natural gas price).

Figure 8-1 also clarifies how a unit retrofitting wet FGD and SCR is affected in competing in wholesale power markets. The total cost of ownership and operation for both wet FGD and SCR for a generating unit is about 80% of the minimum wholesale power price for 2016.

[27] https://www.eia.gov/todayinenergy/detail.php?id=29512

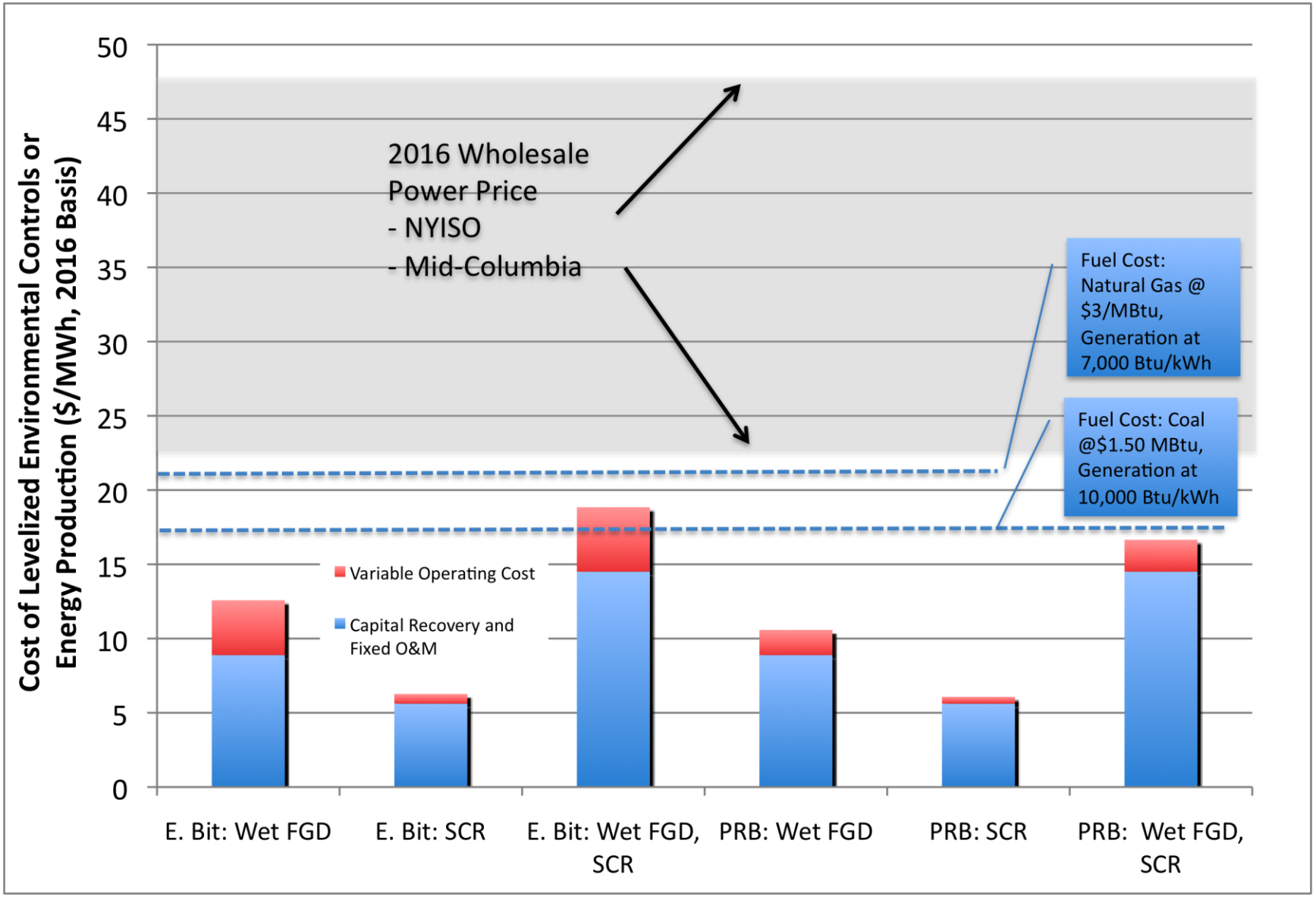

Figure 8-1. Comparison of Control Technology Cost, Wholesale Power Prices, and Fuel Supply Cost

APPENDIX A

EXAMPLE WET FGD CAPITAL COST DATA

Figures A-1 and A-2 present examples of the variability in capital cost observed for wet FGD process equipment over the first two time periods addressed in this evaluation.

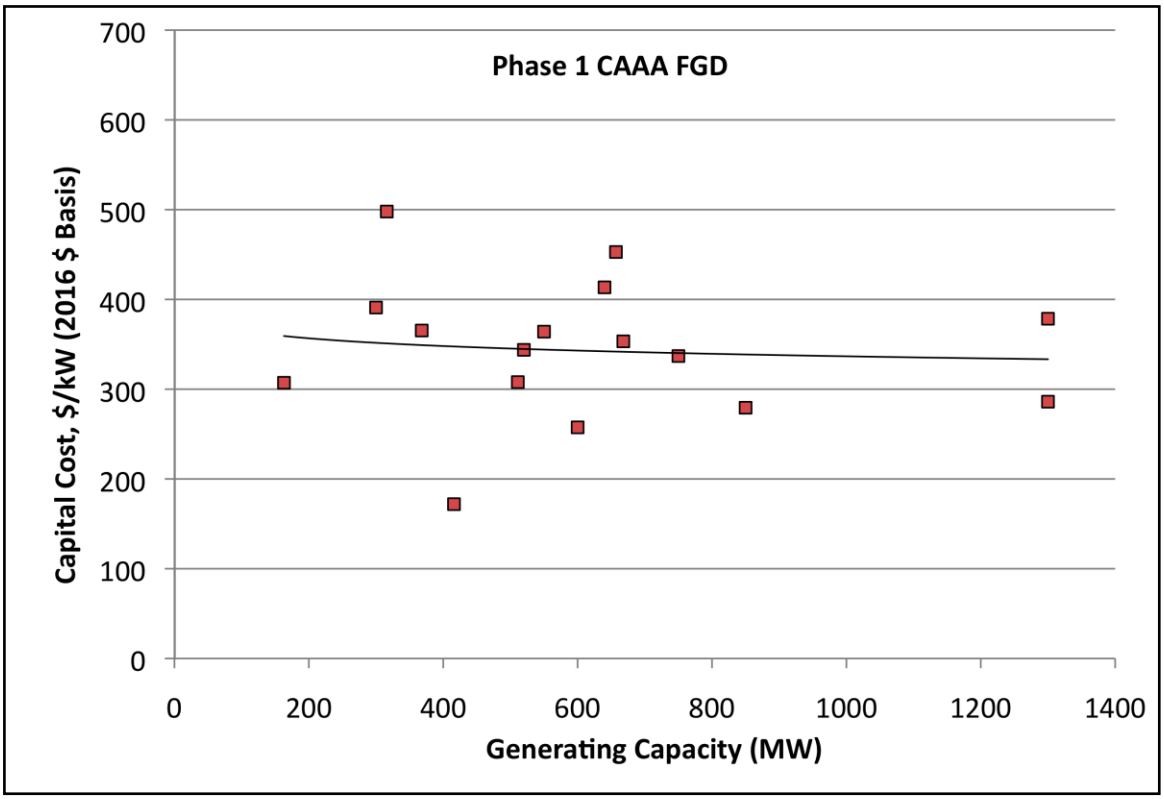

Figure A-1. Individual Cost Data for Wet FGD: Phase 1 CAAA Applications (Curve A of Figure 5-1, 2016 Dollar basis))

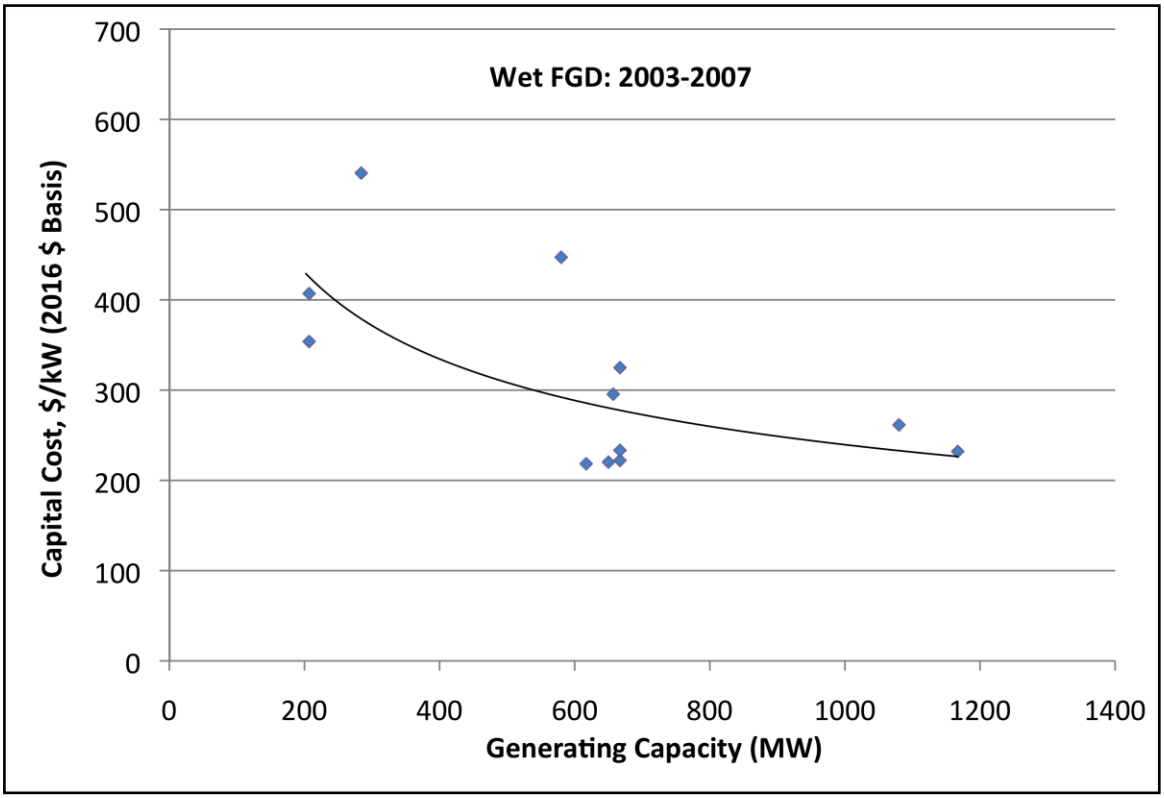

Figure A-2. Individual Cost Data for Wet FGD: 2003-2007 Applications (Curve B of Figure 5-1, 2016 Dollar Basis)

APPENDIX B

EXAMPLE SCR CAPITAL COST DATA

Figure B-1 presents examples of the variability in capital cost observed for SCR process equipment over one of the first three time periods addressed in this evaluation.

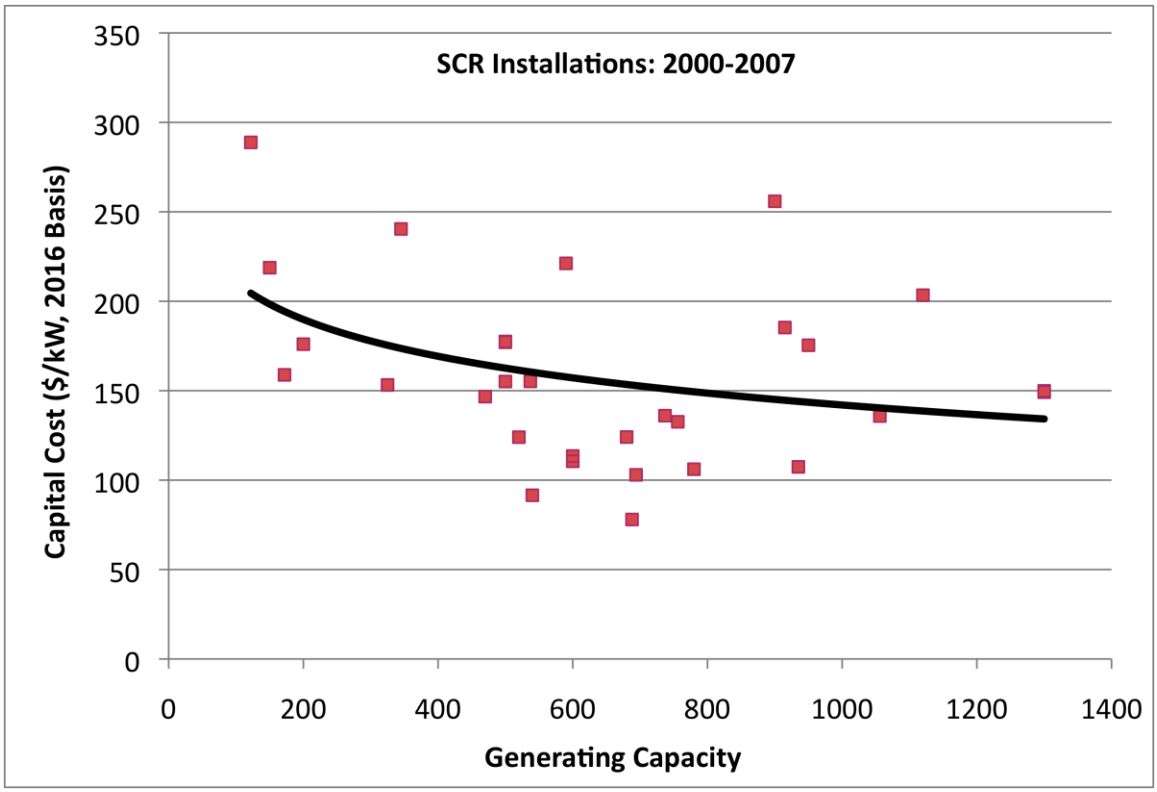

Figure B-1. Individual Cost Data for SCR: Curve B of Figure 6-1 (2016 Dollar Basis)