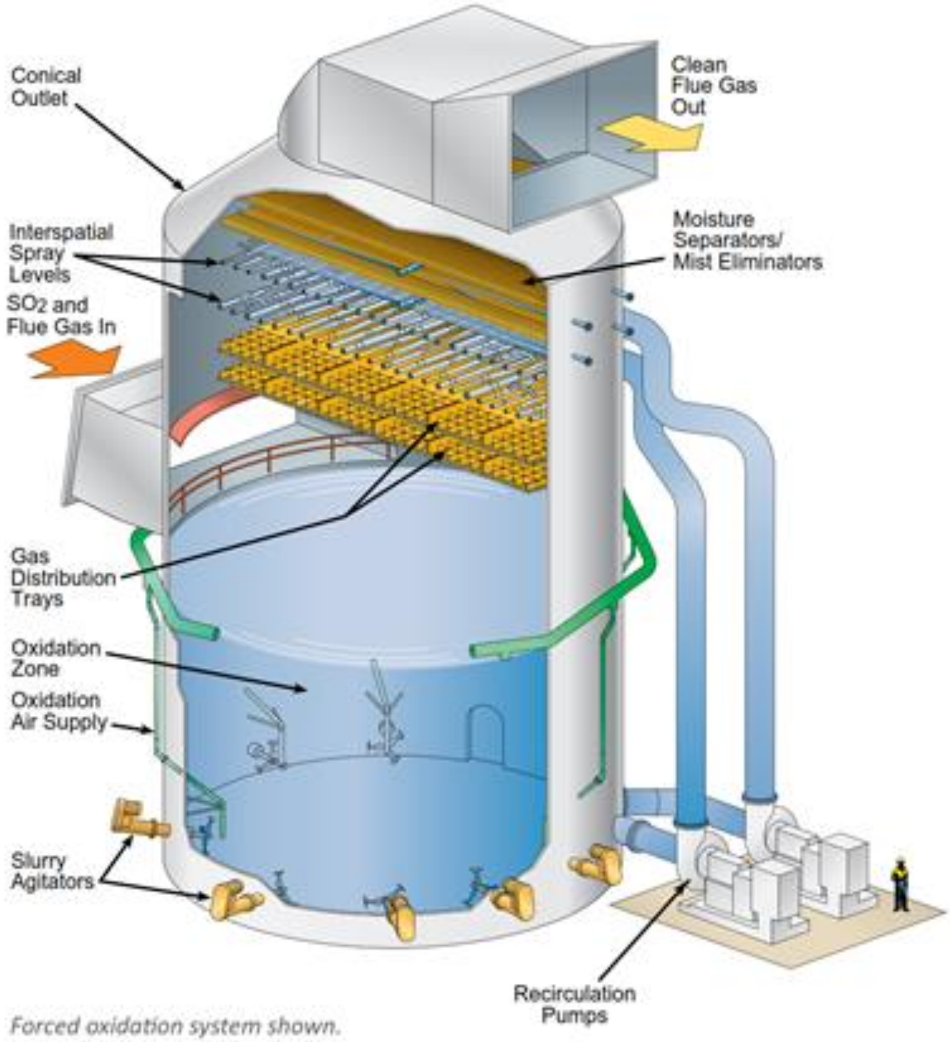
Figure 6. Spray Tower Wet FGD Absorber[11]



Other environmental impacts

Wet FGD will have the following impacts on other air pollutants.

Acid Gases – In addition to SO_2, HCl and other strong acids are removed. As a strong acid, HCl is removed at greater rates than SO_2, which is why the MATS rule permits a scrubbed unit with a controlled SO_2 emission rate continuously measured below 0.20 lb/MMBtu to comply with the HCl emission limit of 0.002 lb/MMBtu without HCl monitoring.

Filterable PM – some additional PM reduction is possible.

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[11] Babcock and Wilcox, WET FLUE GAS DESULFURIZATION (FGD) SYSTEMS ADVANCED MULTI-POLLUTANT CONTROL TECHNOLOGY; available at www.babcock.com

Condensable PM – A wet FGD will reduce SO_3 somewhat, perhaps around 50%. SO_3 is the principal contributor to condensable PM in the form of H_2SO_4 fume.[12]

Mercury – A wet scrubber will generally have a high capture rate for oxidized mercury, but will not capture elemental mercury.[13]

Emissions performance, and improving emissions

Figure 7 shows annual SO_2 emissions for the population of wet FGD systems in the United States for systems operated by coal-fired electric utility or small power producers for the full years of 2011 and 2019. These years were selected because the MATS rule was announced at the end of 2011, and 2019 is the year where we also have HCl emissions data (which will be examined later). The curves show the annual emission rate versus the percent of the total number of units that had annual SO_2 emissions at or below the rate. There are three sets of data shown:

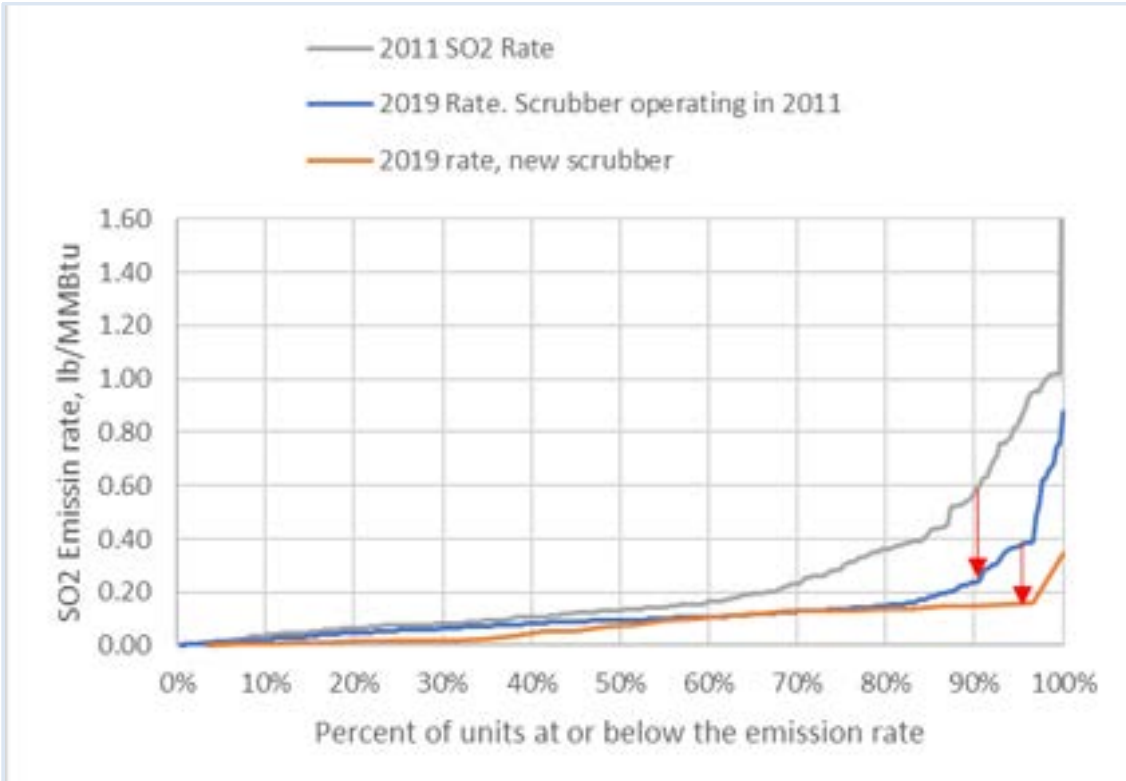
- 2011 emission rate performance of wet FGD systems in the Air Markets Program Data (AMPD) database that operated for a full year in 2011.
- 2019 emission rate performance of wet FGD systems in the AMPD database that operated for a full year in 2011 that were also operating in 2019.
- 2019 emission rate performance of wet FGD systems in the AMPD database that were not operating in 2011 and were operating for a full year in 2019 – that is, they were new FGD systems.

The data shows that in 2011 about 90% of all wet FGD systems had annual SO_2 emissions at or below 0.60 lb/MMBtu, while in 2019 90% of all wet FGD systems that had been in operation in 2011 had emissions below about 0.23 lb/MMBtu. As the red arrows show, there were significant reductions in emission rates between 2011 and 2019. Clearly, many of these facilities took measures between 2011 and 2019 to improve their emissions rates without installing any additional acid gas controls (aside from possible scrubber improvements). In some cases the measures may have simply been increased treatment rates with the existing systems, to include increasing liquid-to-gas ratios. In other cases, there were physical improvements to the FGD system.

[12] Electric Power Research Institute (EPRI), Estimating Total Sulfuric Acid Emissions from Stationary Power Plants 1016384, Technical Update, March 2008, p. 3-10

[13] Illinois Environmental Protection Agency, Bureau of Air, "Technical Support Document for Reducing Mercury Emissions from Coal Fired Electric Generating Units", AQPSTR 06-02, March 16, 2006, p. 118 http://www.epa.state.il.us/air/cair/documents/031406/final-tsd-hg.pdf

Figure 7. Annual SO_2 emission rate for wet FGD systems operating the full year in 2011, 2019 emissions of wet FGD systems that were operating in 2011, and new scrubbers built since 2011.[14]



For the new wet FGD systems put in service after 2011, 90% of the units had SO_2 emissions below 0.15 lb/MMBtu.

Figure 8 shows how many wet FGDs that were in operation improved (reduced) their emission rate between 2011 and 2019. As shown, 71% of existing wet FGDs had an improvement in emissions rates. About 44% of the wet FGD systems improved SO_2 emission rates by 0.05 lb/MMBtu or more. The same data shows that over 50% improved emission rates by over 0.03 lb/MMBtu. As shown in Figure 7, about 40% of wet FGD facilities already had emission rates of 0.10 lb/MMBtu or less in 2011, and therefore may not have had any motivation for reducing emissions further. The average 2011 SO_2 emission rate for those facilities that increased their SO_2 emissions rate between 2011 and 2019 was 0.109 lb/MMBtu and the average increase was 0.0393 lb/MMBtu. So, these facilities could increase their emissions somewhat while remaining below the MATS level of 0.20 lb/MMBtu.

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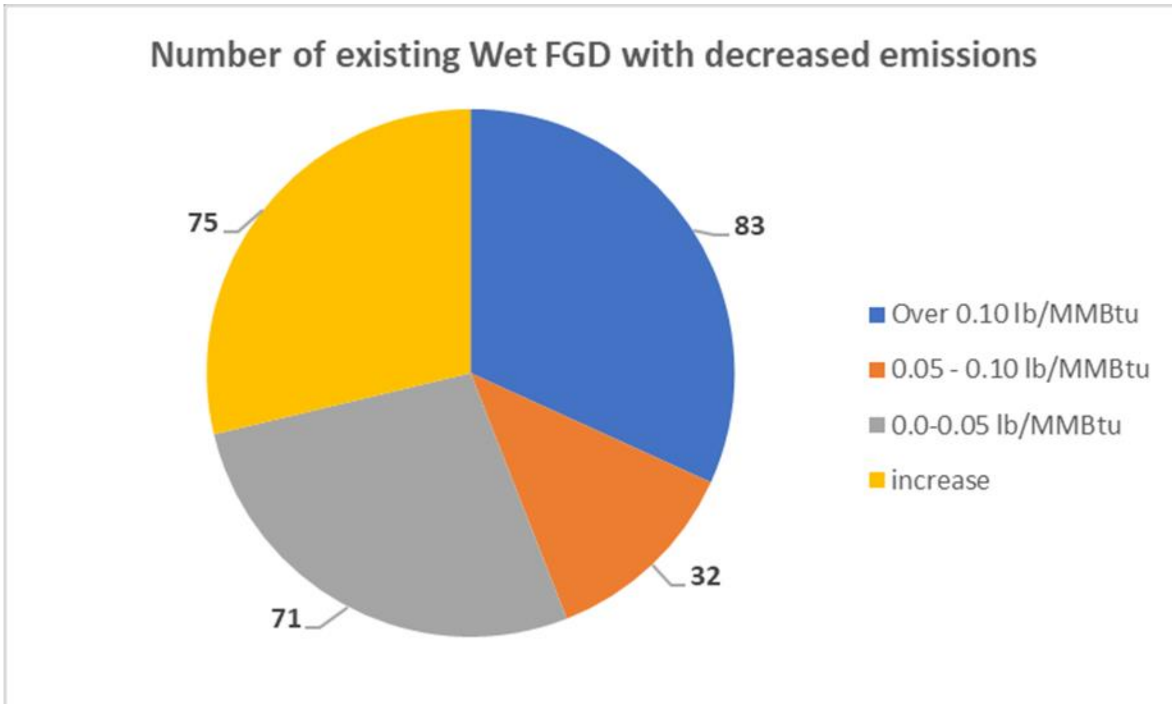
[14] Developed from US EPA Air Markets Program Data for 2011 and 2019. Annual emission rates were determined by multiplying reported emissions in tons by 2000 and dividing the result by reported heat input. The units were then sorted from lowest to highest emitting units according to calculated annual SO_2 emission rate.

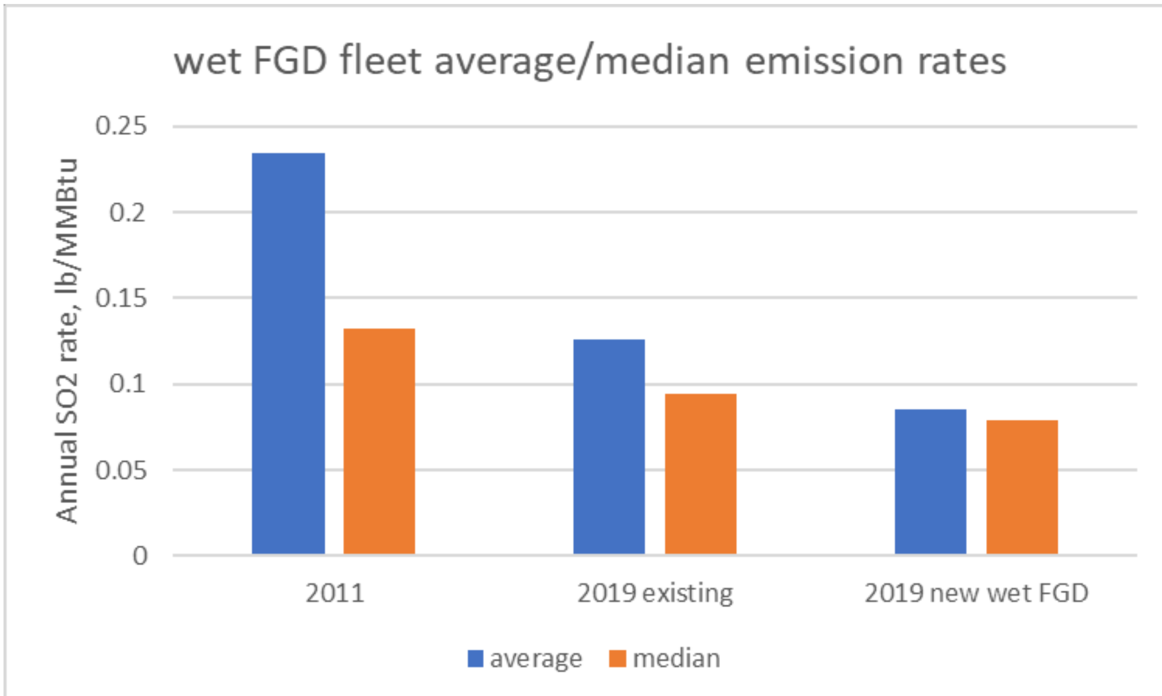
Figure 8. Wet FGD systems operating in 2011 that reduced their SO_2 emission rate in 2019 and how much (units)



This data demonstrates that state-of-the-art wet FGD systems built since 2011 have achieved performance that exceeds that of legacy wet FGD systems. It is also apparent that existing wet FGD systems can be improved.

Figure 9 shows the average and median SO_2 emission rates for the three data sets, demonstrating the significant improvements in performance that have been achieved since 2011. This data demonstrates that state-of-the-art wet FGD systems built since 2011 have achieved performance that exceeds that of legacy wet FGD systems. It is also apparent that existing wet FGD systems can be improved.

Figure 9. Average and median SO_2 emission rate for wet FGD systems operating the full year in 2011, 2019 emissions of units that were operating in 2011, and new scrubbers built since 2011



Performance, or emissions reduction, can be improved to a degree by increases in reagent usage without any physical changes in the FGD system. It is unclear how much of the aforementioned improvements were the result of increases in reagent use versus physical changes in the equipment. The level of improvement suggests that a significant portion of these units may have made physical changes. The following discusses methods to improve performance using physical changes to the FGD equipment.

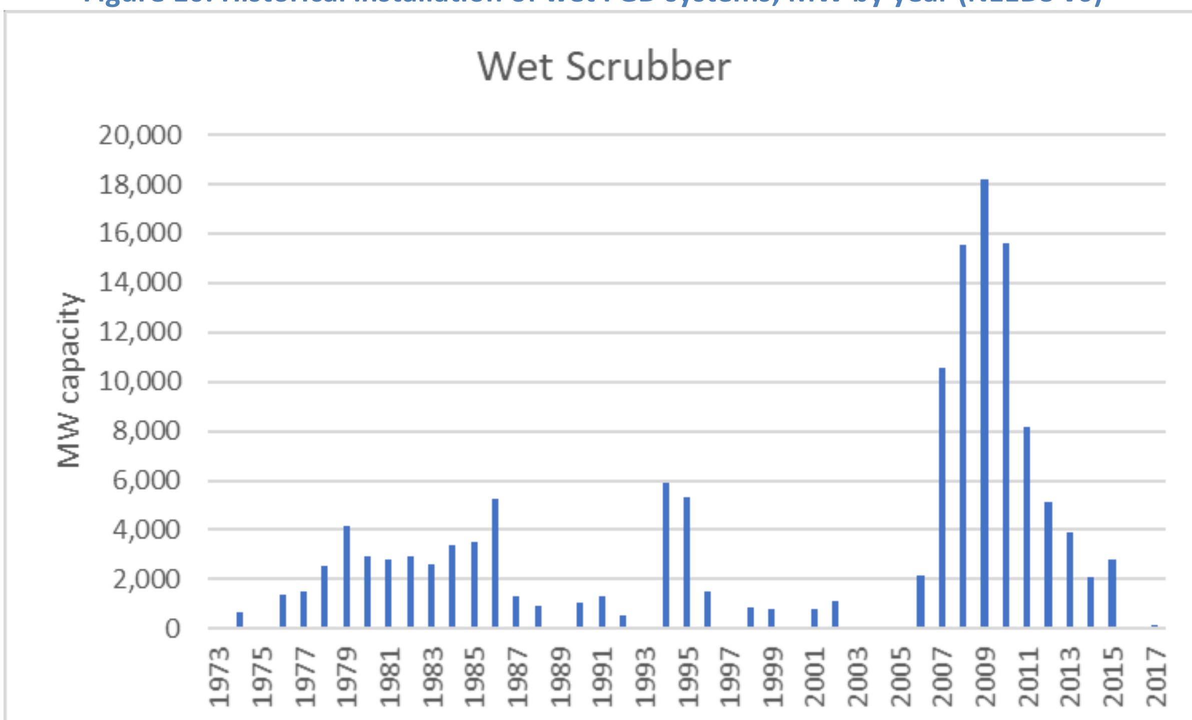
Methods to improve wet FGD performance

Many wet FGDs were built decades ago, using the engineering techniques and the equipment that was available at the time. Figure 10 shows historical installation of wet FGD systems. As shown, a fairly large amount of wet FGD capacity was installed in the 1970s through the 1990s. These were installed with older technology, often without the benefit of modern engineering tools, such as computational fluid dynamics (CFD), that permit design of systems that have higher liquid-to-gas interaction. The aforementioned data demonstrates clearly that wet FGD technology that thas become available since 2011 has substantial improvements in performance over even the improved legacy wet FGD systems, and certainly over the wet FGD systems as installed in 2011. Also, a significant portion of the wet FGD systems that existed in 2011 did implement improvements, but not all did.

For an existing FGD system, an improvement to the FGD system is normally performed without modifying the existing absorber vessel or other, major scrubber island equipment (such as recirculation pumps) because changes to this equipment would be expensive. Improvements include:

- Methods to balance and improve flow through the absorption vessel, or
- Methods to improve liquid/gas contact

Figure 10. Historical installation of wet FGD systems, MW by year (NEEDS v6)[15]



These principles were previously understood, but these improvement methods were not widely deployed until after 2011. This is because the MATS rule motivated utilities to examine how to reduce SO_2 emissions from their wet FGD systems at the lowest cost. Figure 7 and Figure 8 demonstrate that these improvements were deployed on a large number of facilities after 2011. During this deployment, the industry developed innovations that, as will be shown, resulted in wet FGD improvements being far less costly than anticipated by EPA in 2011.

Methods to balance and improve flow through the absorption vessel – This includes using CFD and other modern engineering methods to design improved absorber vessel internals, which

[15] From US EPA National Electric Energy Database System (NEEDS, v6)

may include baffles, trays, or other devices to even flow. This assures that the liquid-to-gas ratio is maintained evenly throughout the flow field. For example,

Figure 11 shows how installation of a tray – essentially, a circular sheet with perforations– balances the flow in the absorber vessel. In the left image, which reflects conditions prior to the upgrade, the red regions in the Spray Header 1 level shows significant unevenness in the flow, meaning that some regions of the gas are being undertreated. The image on the right shows that the red regions are mostly gone with the installation of an internal tray to balance flow. This is a capability that has evolved over the years. The data clearly demonstrates that there is a great deal more experience with these improvement methods since 2011 than before. As a result, there is better understanding of how to execute these methods today than existed in 2011, and, as will be shown later in this report, significant improvements are possible at a much more modest scope and cost than expected in 2011.

Methods to improve liquid/gas contact - Figure 12 shows how improved absorber spray patterns can be used to ensure that there are no untreated portions of the gas. By increasing the number and proximity of nozzles, it is possible to improve the liquid-to-gas interaction.

Figure 13 shows still another example of improvements to a wet FGD system that includes a CFD model, wall rings (rings placed along the wall to prevent gas "sneakage" around the edge of the spray pattern), and bidirectional nozzles. According to the supplier of this approach, this approach provides the following advantages:[16]

<u>CFD Modeling</u>
■ Results in better gas distribution
■ Simulates droplets and full spray coverage over absorber(s)
■ Ensures proper flow along walls
■ Identifies areas requiring additional nozzles for proper liquid and gas distribution
<u>Bidirectional Nozzles Installed</u>
■ Wider-angle spray cone ensures efficient spray pattern through the spray zone
■ Increase gas - liquid collisions
■ Dual direction allows for complete coverage throughout the total spray zone
<u>Wall Baffles</u>
■ Improve distribution of flue gas over entire cross section
■ Reduce "gas sneakage" along absorber walls and corners
■ Minimize pressure drop

[16] Babcock Power, "Wet Flue Gas Desulfurization Scrubber Upgrades", available at: https://www.babcockpower.com/literature-library/

Figure 11 . Example of the use of trays to balance flow through an absorber vessel[17]

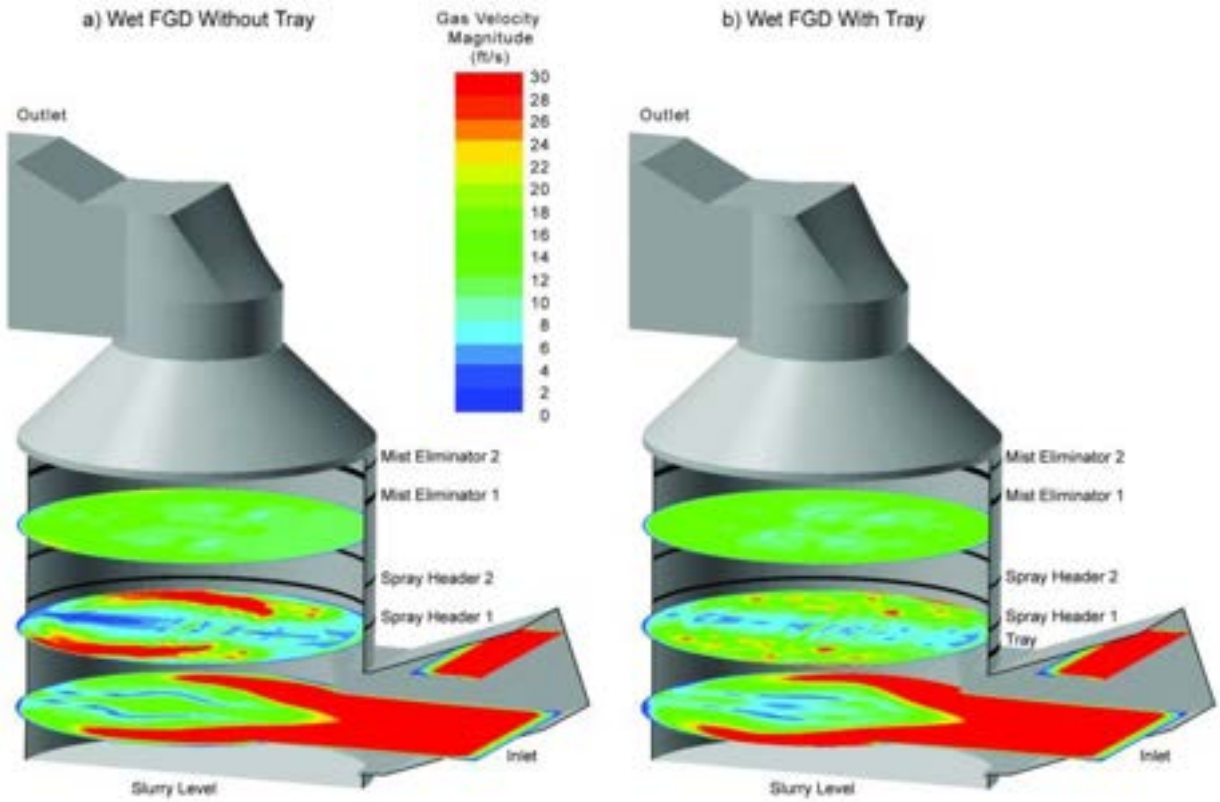
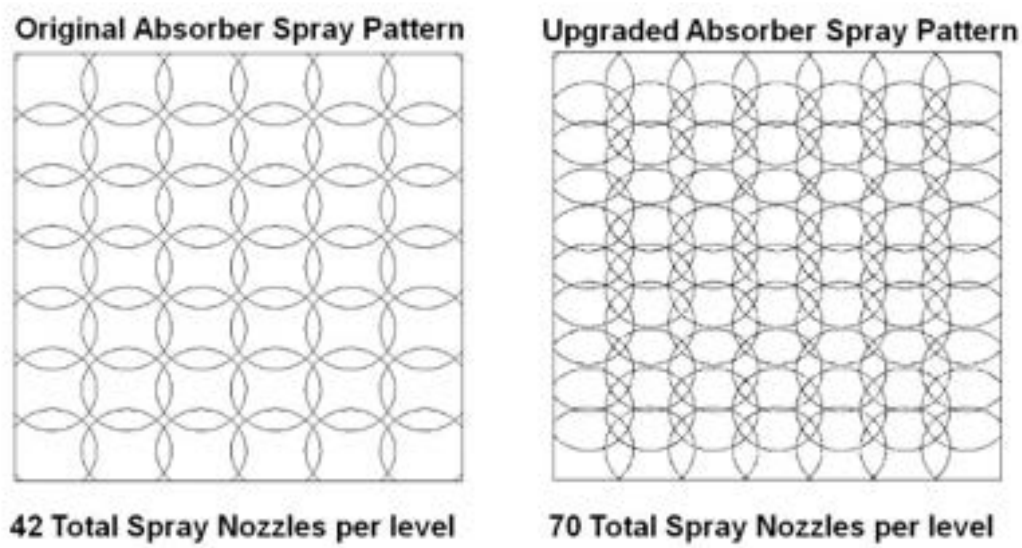


Figure 12. Improved Absorber Spray Pattern[18]



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[17] Moretti, A.L., "State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability", Presented at Power-Gen Europe, June 3-5, 2014, Cologne, Germany

[18] Ibid.

Upgrades to scrubber systems are not commonly reported in the information submitted to EPA. Therefore, comprehensive data on FGD upgrade projects is not available, but the approximate number of improvements are reflected in the emissions data. Six examples of upgrade projects are shown in Table 1, with more information on these specific cases in the source documents. Table 1 shows the improvement in SO_2 removal efficiency for six wet FGD systems that have undergone upgrades of performance.

Figure 13. Use of wall rings and bi-directional flow nozzles to improve FGD performance[19]

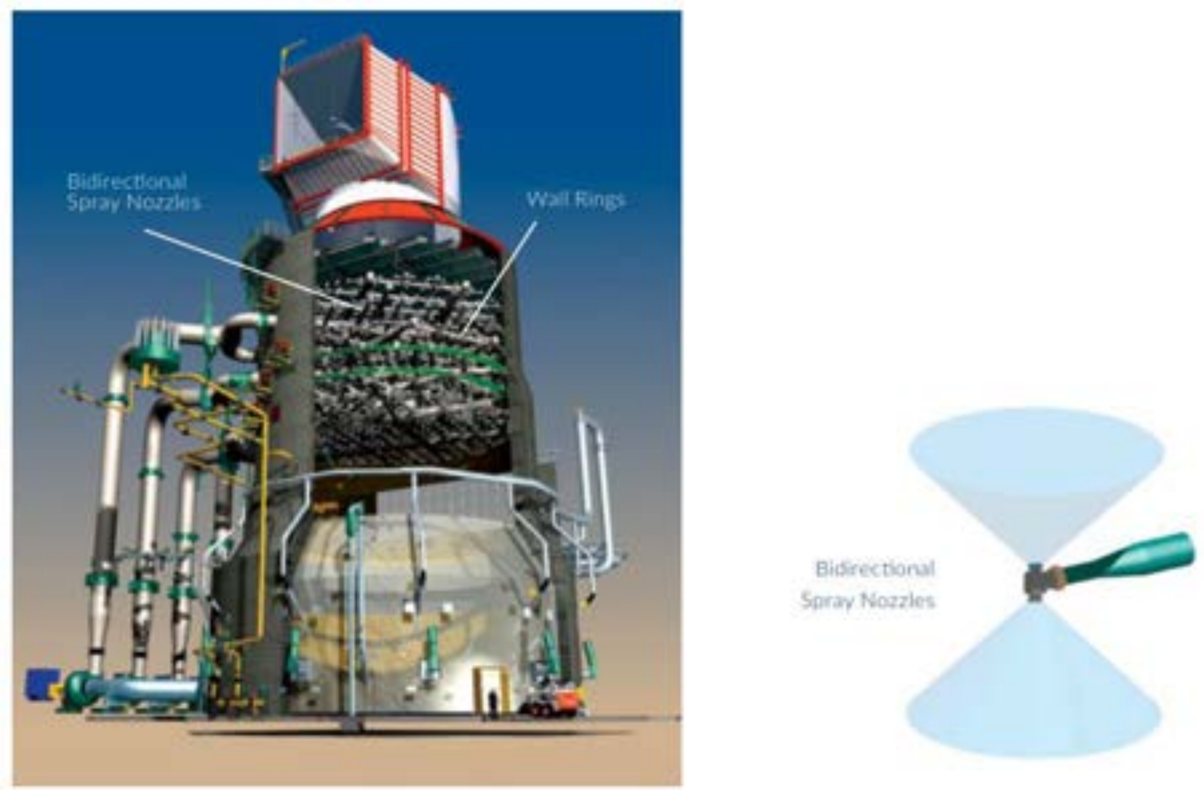

Table 1. Examples of performance improvement for wet FGD upgrades

Case	Starting percent removal	Final percent removal	Source
1	91%	>99%	20
2	93.5%	~98%	20
3	<94%	~98%	20
4	97%	99%	21
5	97%	99%	21
6	80%	97%	21

[19] Ibid.

[20] BabcockPower Environmental, *Wet Flue Gas Desulfurization Scrubber Upgrades*, available at: https://www.babcockpower.com/literature-library/

[21] Parsons, T.R., et al., "Adding a Tray to a Wet FGD Absorption Tower: A Simple but High-Impact Upgrade for an Existing Absorber", Power-Gen Asia, September, 20-22, 2016, Seoul, Korea

Addition of DSI to improve capture of HCl on wet FGD equipped units

Addition of DSI upstream of the PM control device is another option to improve HCl control if upgrades to the FGD are not an option or are not sufficient to reduce HCl to the required level. DSI systems can reduce inlet HCl to the wet FGD by at least 50% and at costs in the range of $40/kW. DSI is explained in more detail later.

Costs of Wet FGD Upgrades

EPA's documentation for the Integrated Planning Model (IPM) indicated that:

"In EPA Base Case v.5.13, coal steam units with existing FGD that do not achieve an SO2 removal rate of at least 90% are assumed to upgrade their FGDs in order to obtain at least 90% SO2 removal and 99% HCl removal. The cost of this "FGD Upgrade Adjustment" is assumed to be $100/kW and is considered a sunk cost for modeling purposes."[22]

This represents EPA's estimate of the cost based upon their envisioned scope of such a retrofit. But, at this point there is more information to estimate the scope of these retrofits.

The cost for performing a wet scrubber upgrade will vary depending upon the particular situation. However, it is possible to make a reasonable estimate of what an upgrade might cost using cost estimates of full scrubber installation and identifying the portions of the full scrubber that are affected.

Although an entire wet FGD system includes an extensive array of support equipment, upgrades to wet FGD systems to improve performance are generally focused on the absorber internals (spray nozzles, flow enhancing devices, etc.). The absorber vessel itself is not changed, nor are the recycle pumps, which are the largest cost items in the absorber island. None of the foundations or structural equipment is changed. It would be a reasonable assumption that the cost of a scrubber upgrade would be some fraction of the cost of the total absorber island. Because the most costly items in the absorber island would be unchanged (absorber vessel, recycle pumps, associated electrical and vessel external piping, support structure), and only internal items to the absorber vessel (spray nozzles, addition of flow control devices such as trays) are changed, an estimate of upgrades on the order of 25% of the cost of an absorber island cost would be very conservative, and likely on the high side.

For US EPA, Sargent & Lundy developed a cost for constructing a wet FGD system with costs allocated to each major system area.[23] The cost estimate is shown in Appendix A. This cost estimate includes an algorithm for the cost of the base absorber island cost equal to:

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[22] IPM v5.13 documentation, Chapter 5, Section 5.5.2

[23] Sargent & Lundy, IPM Model - Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology", January 2017

$$584000*B*((F*G)^{0.6})*(D/2)^{0.02})*(A^{0.716}), \text{ where}$$

- A = unit size in MW
- B = Retrofit factor (1.0 for typical retrofit)
- D = SO_2 inlet rate, lb/MMBtu
- F = coal factor, 1.0 for bituminous, 1.05 for subbituminous, 1.07 for lignite
- G = heat rate factor of C/1000, where C = Gross Heat Rate in Btu/kWh

25% of this would be

$$146000* B*((F*G)^{0.6})*(D/2)^{0.02})*(A^{0.716})$$

Additional costs include costs for engineering, contractor profit, owner's costs, etc., adding another 35%.[24] Other costs would be Allowance for Funds Used During Construction (AFUDC) and Engineering Procure Construction (EPC) fees. AFUDC for an upgrade would be very modest, because an upgrade requires much less time than a full scrubber project, but EPC fees of perhaps 15% may be included. Therefore, if all of the costs but AFUDC are included, this would result in

$$226000* B*((F*G)^{0.6})*(D/2)^{0.02})*(A^{0.716})$$

For the 500 MW example plant shown in the document, this would result in a cost of a wet FGD upgrade of roughly $19 million, or about $38/kW.

EPA estimated the cost of an FGD upgrade to be $100/kW in anticipation of the MATS rule.[25] This is well above what has been estimated here in light of the scope of most of these scrubber upgrades. Although the IPM documentation did not explain the expected cost for an FGD upgrade, it clearly was anticipated in 2011 to be greater than actual costs were after the MATS rule was promulgated. This was likely due to improvements in technology and other techniques for executing these projects that have been gained with experience.

EPA projected that roughly 63 GW of FGD capacity would be upgraded in response to MATS.[26] Given that about 44% of the wet FGD systems in operation in 2011 experienced emission rate reductions of 0.05 lb/MMBtu or more and 51% experienced emission rate reductions of 0.03 lb/MMBtu or more, this is likely greater than the 63 GW that EPA predicted and does not include dry FGD systems. However, because the costs of these improvements are about 38% of what EPA originally estimated, the cost of compliance with MATS was well below the anticipated cost in this regard.

[24] Ibid.

[25] IPM Documentation, v5.13, section 5.5.2

[26] Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, EPA-452/R-11-011, December 2011

Dry FGD

State-of-the-Art dry FGD systems are capable of greater than 95% SO_2 removal. Most power plant dry FGD systems utilize hydrated lime; however, other reagents, such as sodium-based reagents, can be used. Examples of dry FGD systems are spray dryer absorber (SDA) with baghouse and circulating dry scrubber (CDS). Figure 14 depicts an SDA and Figure 15 depicts a CDS. In both the case of SDA and CDS, downstream PM removal devices are necessary and baghouses are most commonly used. CDS systems can generally achieve higher removal rates in high SO_2 environments than SDA systems because moisture and reagent are added independently of each other in a CDS system.

SDAs using lime reagent can become less efficient with high sulfur coals and high removal rates, so they are most often applied in low sulfur coal applications. CDS systems can achieve higher removal rates than SDA systems on high sulfur coals because moisture and lime reagent are added independently of one another.

SDA and CDS systems reduce particulate matter emissions because a fabric filter is commonly used downstream of the absorber vessel to capture the solids.

Dry lime FGD (such as SDA and CDS technology) is widely used today and has become more cost effective partly due to cost improvements in the baghouse – a large part of the total cost of a dry scrubber. Modern baghouses typically use pulse-jet technology while older baghouses used reverse-air technology. Pulse-jet fabric filters have higher air-to-cloth ratios, meaning that less cloth is needed to treat the same gas flowrate, and the baghouse can be smaller. This means that a pulse-jet fabric filter can be smaller and less expensive than a reverse air fabric filter treating the same gas flowrate.

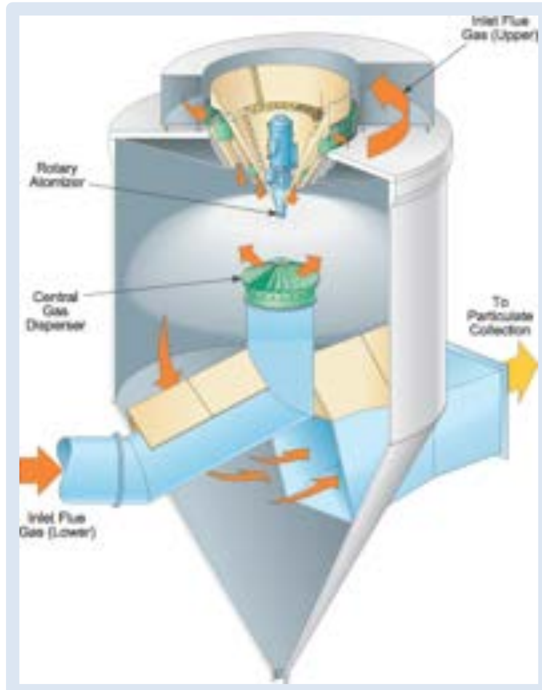

Figure 14. A Spray Dryer Absorber

Lime reagent and water mixture are atomized and coinjected into a reaction vessel with flue gas. As the injected droplets dry, they react with SO_2 in the gas and the dry product is sent to a fabric filter for capture.[27]

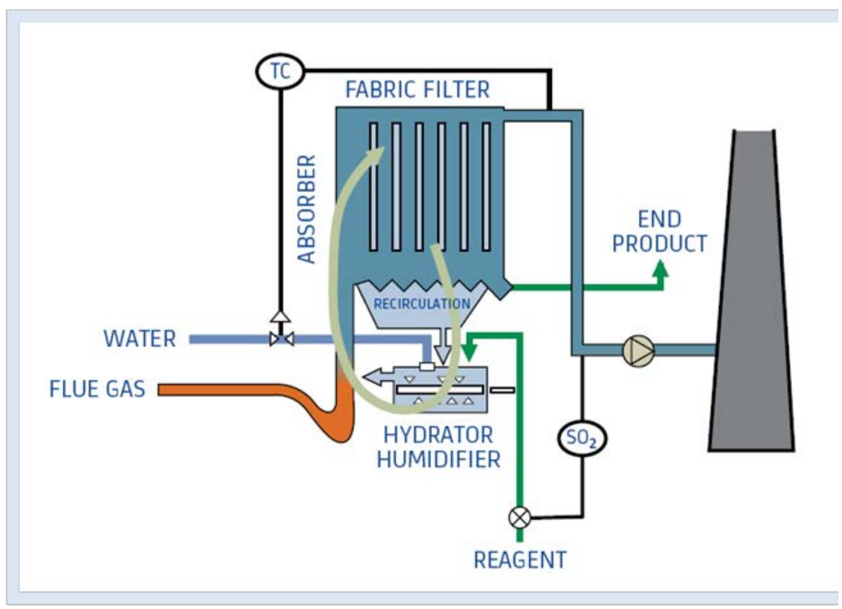

Figure 15. A Circulating Dry Scrubber – Lime reagent and water are introduced separately to cool gas and make a humidified reagent. The lime reacts with SO_2 in the cooled gas. The dry product is captured in a fabric filter and recirculated to increase reagent utilization.[28]

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[27] Staudt, J. E., "Candidate Control Measures for Industrial Sources in the LADCO Region", for Lake Michigan Air Directors Consortium, January 24, 2012, page 67 http://www.ladco.org/reports/so_2_reports/C_11_011_LADCO_SO2_Final.pdf

[28] Ibid.

CDS technology can provide 96% removal and 0.15 lb SO_2/MMBtu emissions with coal that would produce 3.6 lb SO_2/MMBtu uncontrolled, as demonstrated at the AES Greenidge plant. Table 2 shows coal fired utility boilers where the Babcock Power Turbosorp (a CDS technology) is applied and Table 2 shows where Turbosorp and other CDS systems have been applied.

Energy Impacts

Dry FGD will increase the parasitic loads on the plant due to the pressure drop across the fabric filter, the increased induced draft fan demands and other power demands such as compressed air.

Other Environmental Impacts

Dry FGD will have the following impacts on other air pollutants:

Filterable PM – All dry FGD systems have fabric filters. As a result of the addition of a fabric filter, filterable PM emissions will likely be reduced if dry FGD is deployed.

Mercury – For bituminous fuel boilers dry FGD systems will result in high mercury capture because SO_3 (which inhibits mercury capture) is removed efficiently and the mercury is readily captured on the fabric filter. At the AES Greenidge dry scrubber, over 95% total mercury capture was achieved without use of activated carbon.[29] For Powder River Basin (PRB) fueled boilers it may be necessary to add halogen in the form of a coal additive or halogenated activated carbon. In this case high mercury capture is possible.

Condensable PM – Very high reductions of SO_3 and H_2SO_4 are expected from dry FGD systems with a baghouse, and higher than 95% SO_3 reduction was measured at the AES Greenidge dry scrubber.[30, 31]

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[29] Connell, D., "GREENIDGE MULTI-POLLUTANT CONTROL PROJECT - Final Report of Work Performed", Report to US DOE, May 19, 2006 – October 18, 2008, pages 153, 154

[30] Electric Power Research Institute (EPRI), Estimating Total Sulfuric Acid Emissions from Stationary Power Plants 1016384, Technical Update, March 2008, p. 3-11

[31] Connell, D., "GREENIDGE MULTI-POLLUTANT CONTROL PROJECT - Final Report of Work Performed", Report to US DOE, May 19, 2006 – October 18, 2008, pages 153, 154

Table 2. Turbosorb and other Dry Scrubber Systems (note, CFB Scrubber in this table denotes Circulating Fluidized Bed scrubber and is the same as a CDS system as described in this report) from Wisconsin Department of Natural Resources, "BART Determination – Amended July 2011 Georgia Pacific Broadway Mill, Green Bay Wisconsin", Facility ID 405032870, July 1, 2011, page 9[32]

		From Babcock Power			From NEEDs Database				From NPS BART Compilation (updated 08/2010)					
	GP	Greenidge - NC *	Deerhaven - FL (Case 1) *	Deerhaven - FL (Case 2)*	Altavista - VA	Southampton - VA	Roanoke - NC	Edgecombe - NC	Eastman - TN (non-EGU)	Stanton - ND	Stanton - ND	Pacificorps - WY	CSU - CO	CSU - CO
Control Technology	CFB (Turbosorp)	CFB (Turbosorp)	CFB (Turbosorp)	CFB (Turbosorp)	SDA	SDA	CFB	SDA	SDA	CFB	SDA	SDA	SDA	SDA
Installation Date	---	2006	2010	2010	1992	1995	1995	1990	---	---	---	---	---	---
Heat input (mmbtu/hr) and/or MW output	965 (75 MW)	107 MWe	238 MWg	238 MWg	31.5 MW x2	63 MW	44 MW	28.9 MW	655 x 5	1,800	1,800	2,500	1,336	850
Pre-control (tpy)	10,889	14,877	N/A	N/A	N/A	N/A	N/A	N/A	14,309	9,376	9,376	13,316	4349	2853
Pre-control (#/mmBtu)	3.48	3.62	3.8	2.2	Fuel limited to 1.5% S	Bituminous	Fuel limited to 1.6% S	Bitum.	2.4	2.4	2.4	1.21	0.99	1
Post-control (tpy)	762	---	N/A	N/A	N/A	N/A	N/A	N/A	379	656	938	1,656	739	485
Post-control (#/mmBtu)	0.25	0.13	0.11 (WDNR estim.)	0.10 (WDNR estim.)	0.19	0.162 (limit)	N/A	0.31 (limit)	0.20	0.17	0.24	0.15	0.13	0.13
% reduction	93	96.3	97.2 *	95.4 *	95% required (95-96% actual)	92% required (96% actual)	93% required	90% required (95% design)	92	93	90	87.6	83	83

[32] http://dnr.wi.gov/topic/AirQuality/documents/HazeSIPBARTAttachment3.pdf