Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants

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Executive Summary

This study examined acid gas emission control methods and acid gas emission rates for the fleet of 543 coal fired units operating in 2019, with the objective of trying to identify what opportunities may exist for further reduction of acid gas emissions in the coal fleet. The study examined improvements in performance, improvements in technology, or deployment or development of new technologies in the period between 2011 and 2019. 2011 was the year that the Mercury and Air Toxics Standards (MATS) rule was developed. 2019 reflects a time after MATS was deployed and where data was collected on HCl emissions and unit characteristics in a database on NRDC's website.[1] Other sources of data used in this effort include US EPA's Air Markets Program Data (AMPD) and US EPA's National Electric Energy Database System (NEEDS). For those units where HCl data was available, it was organized into deciles to examine important trends. With this data, this study examined the improvements in the performance of acid gas control techniques over the period between 2011 and 2019.[2] It examined what the costs of these improvements are, and how widely these improvements could be deployed. It also examined what HCl emissions levels might be possible and the costs associated with achieving those emission levels.

This study finds that there are opportunities to improve acid gas emissions further, in part due to improvements in emission control technology (i.e. lower potential emission levels for any given cost), reduction in the cost of controls, and availability of ways to improve performance of existing controls. These are summarized below according to the acid gas control technology.

Methods to reduce acid gas emissions

Wet FGD – In 2019 about 160 GW of capacity (62% of coal capacity) and 300 coal units (56% of coal units) were equipped with wet flue gas desulfurization (FGD). 29 of the the 300 coal units equipped with wet FGD in 2019 systems were units with new wet FGD systems installed since 2011. Some of the new FGD systems since 2011 were installed on new generation and others were installed primarily to comply with Regional Haze plans, the Cross-State Air Pollution Rule (CSAPR), or other requirements beyond MATS. Most of the wet FGD equipped units use bituminous coal. For those wet FGD equipped units that were in operation in 2011, there have been significant improvements in emissions, with roughly 50% having an emission rate improvement of 0.03 lb/MMBtu of SO_2 or more between 2011 and 2019. About 32% of the units equipped with wet FGD in 2011 did not have an improvement in SO_2 emission rate. Therefore, a

[1] https://www.nrdc.org/resources/coal-fired-power-plant-hazardous-air-pollution-emissions-and-pollution-control-data. Because most units demonstrate compliance through other means, HCl emission rates were available for 89 units that includes both scrubbed and unscrubbed units.

[2] Bearing in mind that the facilities that did not provide HCl data were scrubbed units with sufficiently low SO2 emissions to demonstrate compliance, it is likely that the available HCl data is not reflective of the best controlled units.

significant portion of the wet-FGD equipped coal fleet deployed upgrades in wet FGD technology or improved the performance of their existing controls. New FGD systems placed in service after 2011 demonstrated significantly lower 2019 SO2 emissions than the 2019 SO2 emissions for systems that had been installed in 2011. Estimates of the cost of control improvements were made based upon the reported scope of some improvement projects,[3] which largely used improvements in absorber flow balancing and atomization methods, which was the most commonly used approach to improving wet FGD. Costs to upgrade wet FGDs were estimated to be in the range of $38/kW for a 500 MW unit. This cost estimate is significantly below what had been assumed by EPA in development of the MATS rule.

Dry FGD – In 2019 about 40 GW of capacity (15% of coal capacity) and 88 units (16% of coal units) were equipped with dry FGD. 32 of these systems were new dry FGD systems installed since 2011. Some of the new FGD systems since 2011 were installed on new generation and others were installed primarily to comply with Regional Haze plans, CSAPR, or other requirements beyond MATS. Most of the dry FGD equipped units use subbituminous coal. For those dry FGD equipped units that were in operation in 2011, there have been significant improvements in emissions, with roughly 35% experiencing an SO_2 emission rate improvement of 0.03 lb/MMBtu or more. About 33% of the units equipped with dry FGD in 2011 did not have an improvement in SO_2 emission rate. Therefore, it appears that a significant portion of the dry FGD equipped coal fleet deployed upgrades in dry FGD technology or improved the performance of their existing controls. New FGD systems placed in service after 2011 had lower 2019 SO_2 emissions than the 2019 SO_2 emissions for systems that had been installed in 2011, but not to the same degree of improvement over existing systems as observed with wet FGD. Estimates of the cost of control improvements were made based upon the reported scope of some improvement projects, which largely used improvements in atomization or fabric filters. Costs were estimated to be in the range of $17/kW for atomization improvements and about $5/kW for fabric media improvements on a 500 MW unit. This cost estimate is significantly below what had been assumed by EPA in development of the MATS rule.

DSI – In 2019 about 30 GW of capacity (11% of coal capacity) and 66 units (12% of coal units) was equipped with dry sorbent injection (DSI). DSI usage for SO_2 control in 2011 was very limited. DSI is a lower cost option than a wet or dry FGD system for improvement of acid gas emissions for units with no other form of acid gas controls.[4] The degree of HCl control will be dependent upon treatment rate and the type of particulate matter (PM) controls. HCl capture will depend in part on the sorbent used and the PM capture device that is used. HCl is captured more effectively with DSI than SO_2. However, about 70% or more HCl capture is expected with an

[3] Six projects and seven FGD systems, based upon published technical papers. Notably, companies do not routinely report these upgrade projects in the same manner that they report new FGD installations. Therefore, it is necessary to rely upon those projects where technical papers were published.

[4] DSI can also be used in combination with activated carbon injection (ACI) for Hg control, although one may impact the other to a degree.

electrostatic precipitator (ESP) and over 90% capture is expected with a fabric filter (also known as a baghouse, or "BH"). DSI equipped units with fabric filters averaged an HCl emission rate of 0.00012 lb/MMBtu and units with DSI and ESPs averaged 0.00077 lb/MMBtu. Capital cost will be impacted by treatment rate, as storage and transport equipment are a significant portion of the cost, but may be in the range of $40/kW. Since 2011, there have been improvements in both reagents and improvements in the injection systems. The impacts have been to improve capture with lower cost reagents. Upgrades of reagent injection systems to existing DSI systems should enhance capture by about 25% (or, alternatively, reduce injection rates to achieve the preexisting capture percentage) at a capital cost of under $10/kW.

PM controls only – PM controls include electrostatic precipitators, baghouses, and combinations of the two.[5] Units with only PM controls may improve their acid gas emissions through addition of an acid gas control technology, such as FGD or DSI. They may also improve performance by adding a baghouse downstream of the ESP, which appears to provide some benefit to HCl control, but will provide even more benefit if combined with a DSI system. A fabric filter installation downstream of the existing ESP costs in the range of $150-$200/kW.

Trends in HCl emissions

Examination of HCl emission trends showed that the best controlled units were likely to be scrubbed (i.e., have an FGD system) or have combination ESP and fabric filter control systems with DSI. There was only one dry FGD equipped unit among the 89 units where HCl emission rate data was available, but it was among the best controlled units. Analysis of wet FGD equipped units showed a significant relationship between SO_2 emission rate and HCl emission rate, confirming that units with lower SO_2 emission rates are generally expected to have lower HCl emission rates.

The data suggests that wet FGD equipped units achieving an SO_2 emissions rate of 0.20 lb/MMBtu have lower HClemissions rates than is required, meaning lower HCl rates are possible. In other words, the surrogate SO_2 limit corresponds to a lower HCl emission rate than 0.002 lb/MMBtu. For the 14 wet FGD equipped units that provided HCl data and had SO_2 emissions at or below 0.20 lb/MMBtu, the highest HCl emission rate was 0.000737 lb/MMBtu.

DSI equipped units with a fabric filter demonstrated very low HCl emissions, at approximately the same level as the unit with dry FGD and a fabric filter. DSI equipped units with ESPs, not unexpectedly, had significantly higher HCl emissions than those with fabric filters. Lower SO_2 emission rates tended to correspond with lower HCl emissions. This was an impact of the PM control device and likely the coal type used.

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[5] Consistent with industry practice, in this report the terms "baghouse" and "fabric filter" are used interchangeably. Combinations of an ESP and fabric filter (or baghouse) are often called a "compact hybrid particle collector," or "COHPAC." The use of a wet scrubber without either an ESP or baghouse is extremely rare – only one unit in the fleet.

For units reporting no acid gas controls, there was significant scatter when HCl emissions were compared to SO_2 emissions, except for units with both an ESP and a baghouse. For units with both an ESP and a baghouse, HCl emissions were consistently fairly low, resulting in a lower average HCl emission rate than for units with only an ESP or a baghouse.

Opportunities to improve acid gas control performance and associated costs

There are opportunities to reduce acid gas emissions further based on developments in the industry. These have been estimated to be:

Estimated impact of reduction in acid gas emission rate standard[6]

HCl Limit (lb/MMBTU) *(Current HCl standard is 0.002 lb/MMBTU or 0.20 lb/MMBtu SO_2 (as a surrogate for regulated acid gases) for units with FGD)*	**Control improvements likely to result**	**Costs for fleet as a whole** *(Preliminary estimates)*
0.001 lb/MMBtu HCl	• Some units with no acid gases controls install DSI	• ~$60 million annualized capital cost for units with no acid gas controls
	• Some ESP units upgrade DSI	• Roughly $21 million annualized capital cost for units with DSI
	• Few wet FGD units are impacted	• About $19 million in annualized capital cost for units with wet FGD
0.0006 lb/MMBtu HCl	• Most units with no acid gas controls install DSI	• About $120 million in annualized capital cost for units with no acid gas controls
	• Units with DSI and ESPs upgrade DSI system or add BH • Little or no impact for units with DSI and baghouses	• Assuming 30% of ESP equipped units install baghouse and 30% of ESP equipped units install DSI improvements, total cost is $118 million annualized capital
	• About 15% of wet FGD units and 30% of dry FGD units impacted, although dry FGD units likely comply on basis of HCl emission	• ~$42 million annualized capital cost for scrubber improvements
0.0001lb/MMBtu HCl	• Units with no acid gas controls install baghouses and DSI	• ~$494 million annualized capital cost for DSI and baghouses
	• Units with DSI and ESP install baghouse • Units with DSI and baghouse may need to upgrade DSI	• ~$382 million annualized capital cost for DSI improvements for baghouse equipped units and baghouses for ESP equipped units
	• Most scrubbed units impacted. Improvements or DSI on 75% of wet FGD capacity and improvements on 25% of dry FGD capacity	• ~$475 million annualized capital cost for scrubber improvements

6 These cost estimates do not take into account all retirements that have occured since 2021, and therefore likely overstate costs.

Analysis Results

This study examined the results of implementing the 2012 MATS rule, and improvements in techniques for acid gas control since 2012, to determine what additional acid gas reductions are achievable. The study elements included assessments of:

Methods to reduce acid gas emissions, especially HCl, from the exhaust gases of coal-fired power plants. This includes methods that capture acid gases, such as wet and dry FGD and DSI. The installed base of acid gas controls for coal fired power plants was examined. For scrubbed units (i.e., units that had either wet or dry FGD), trends in emissions of SO_2 between 2011 and 2019 were examined to see to what degree emission rates improved on existing facilities during this period and compared to emissions of facilities with FGD systems that were placed in service over this period. It also examined what improvements were developed and potentially deployed during that period to permit greater control of acid gas emissions through improvements to the existing systems.

Trends in HCl emissions were examined to see what levels of control are possible for HCl using different emission control technologies. Because the majority of facilities with scrubbed units demonstrate compliance through maintaining SO_2 emissions below 0.20 lb/MMBtu, there is a limited amount of data on measured HCl emissions, but this includes a significant number of units with wet FGD, DSI and those without any SO_2 controls. This data on 89 units was examined to see what trends existed with regard to HCl emissions and control technologies, coal types, PM control and SO_2 emission rates.

Opportunities to improve acid gas control performance and associated costs were examined to estimate the approximate costs to the coal fleet of reductions in the acid gas emission rate requirement.

I. Methods for reduction of acid gas emissions

Methods for reducing acid gas emissions from coal-fired power plants include changing fuels or blending fuels, as well as adding control technology to remove acid gases from power plant exhaust gases and monitoring acid gas emissions to ensure that controls are functioning properly. This study will focus on the control technologies that are available for capturing acid gas emissions.

Acid gases include emissions of sulfur dioxide and of HCl, HF and other strong acids that may result from halogens in the coal when it is combusted. MATS set an emission limit of 0.0020 lb of HCl per million Btu of heat input. With the exception of low mass emitters, this emission standard could be met in a number of ways:

- Quarterly stack testing of HCl may be used to demonstrate compliance
- Use of an HCl continuous emission monitoring system[7]
- For units with wet or dry FGD systems, maintaining an SO_2 emission rate below 0.20 lb/million Btu. This is because HCl is removed more efficiently by FGD systems than SO_2, and at these emission levels it is presumed that HCl emissions are below the standard.

This report utilized an emissions database available from the NRDC website[8] that compiled the HCl emissions data reported for each unit in 2019. In addition to this database, ATP used 2019 Air Markets Program Data (AMPD) directly downloaded from US EPA's website for some of the analysis as well as US EPA's National Electric Energy Data System (NEEDS v6). NEEDS v6 from 2019 was used to assure temporal consistency with other data that was used in this study.

A. METHODS FOR CAPTURING ACID GASES

There are three principal means for capturing acid gases from the exhaust gases of coal-fired power plants: wet FGD systems, dry FGD systems, and dry sorbent injection (DSI) systems. Average SO_2 emission rates for 2019 are shown in Figure 1. As shown, the average emission rate for wet FGD is somewhat lower than for dry FGD. Notably, most units that burn high sulfur coal utilize wet FGD because a lower cost reagent – limestone – can be used. Although both wet and dry FGD have potentially high capture rates, wet FGD is capable of slightly higher SO_2 capture

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[7] Increased HCl data availability through more widespread use of HCl CEMS would enable operators to monitor and improve operation and acid gas capture, and likely further reduce acid gas emissions from what is already achieved.

[8] https://www.nrdc.org/resources/coal-fired-power-plant-hazardous-air-pollution-emissions-and-pollution-control-data, Importantly, this database was additionally checked for consistency with some of the other reported data, such as that from the AMPD. Because this database was compiled from many other sources of data, there were a small number of duplicates that were found that were resolved. Also, in a small number of cases where the database indicated no SO_2 controls on the units, the reported 2019 SO_2 emission rate appeared too low. Comparison against 2019 AMPD data showed that these units actually did have emissions controls. Therefore, all of the analysis in this report that used this database incorporates these corrections.

efficiency, but this does not necessarily mean higher HCl capture efficiencies. DSI, on average, controls to about 0.25 lb/MMBtu, but as will be seen later, there is a range of control levels.

Wet FGD is by far the most commonly used SO_2 control technology, whether measured by number of units or by capacity installed (Figure 2). There are still a significant number (and capacity) of coal units that do not have any controls for acid gases. Figure 3 shows the PM control methods that are deployed. COHPAC are those cases where an ESP and baghouse are used in combination with the baghouse following the ESP. The ESP and baghouse totals shown include COHPAC installations. In this case, the baghouse follows an ESP, with the ESP capturing most of the PM and the baghouse capturing the remaining PM plus any flue gas treatment sorbents (such as activated carbon, trona or lime) that may be introduced downstream of the ESP. The latter configuration, in which treatment sorbents are added between the ESP and the baghouse, is also known as a "toxic emissions control device," or "TOXECON."

Figure 1. Average 2019 SO_2 Emission Rate for MATS affected coal-fired utility boilers

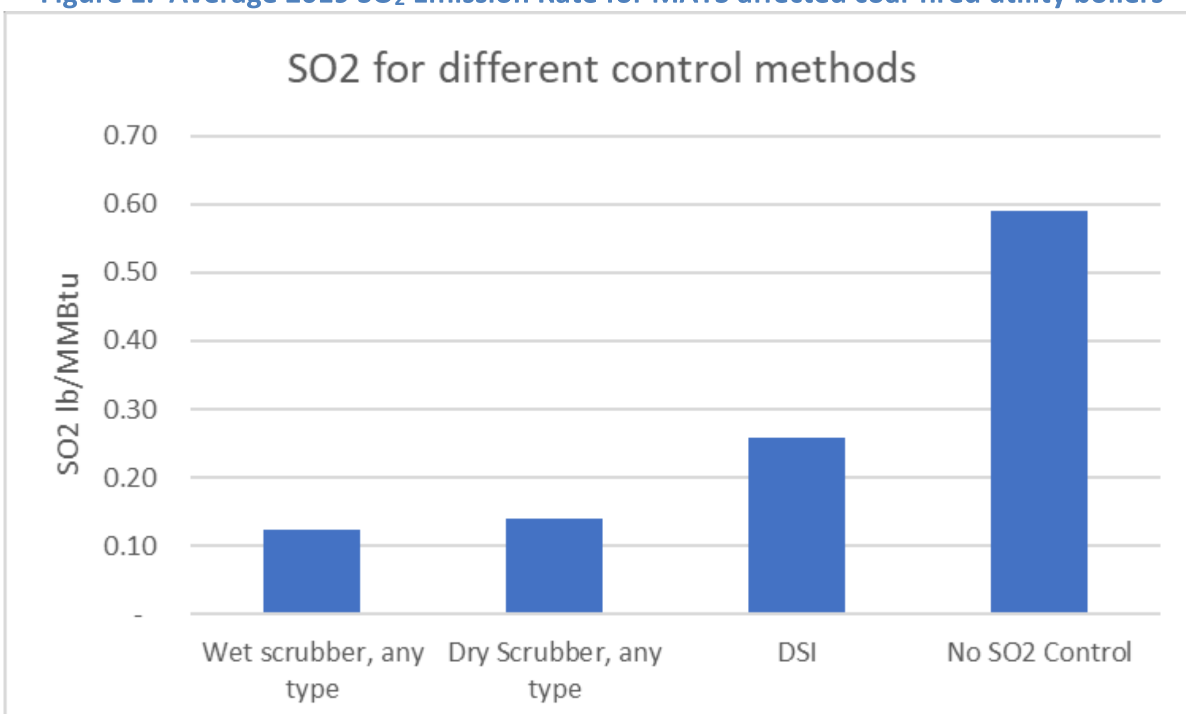


Figure 2. SO2 control technology in 2019

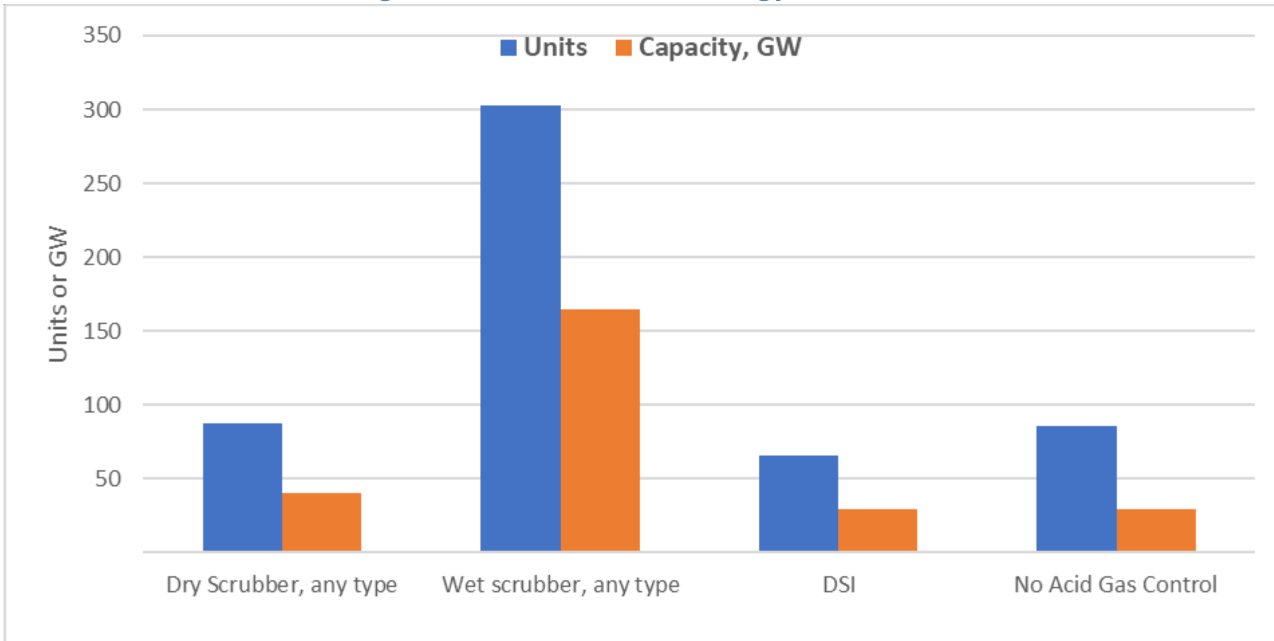
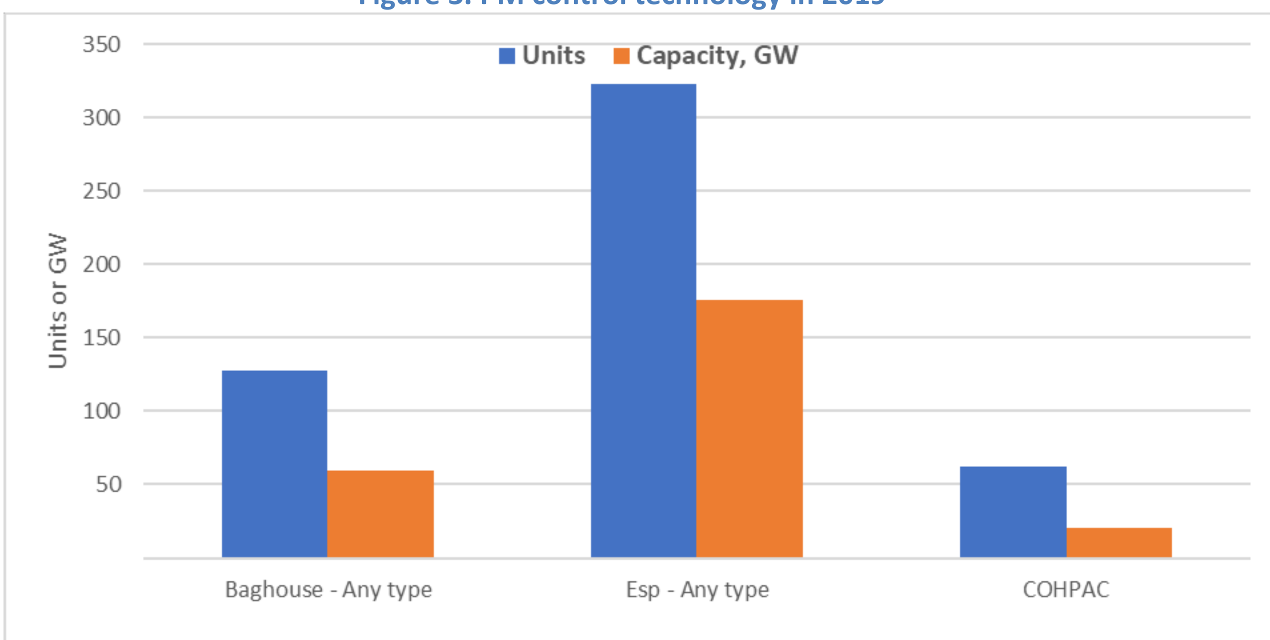


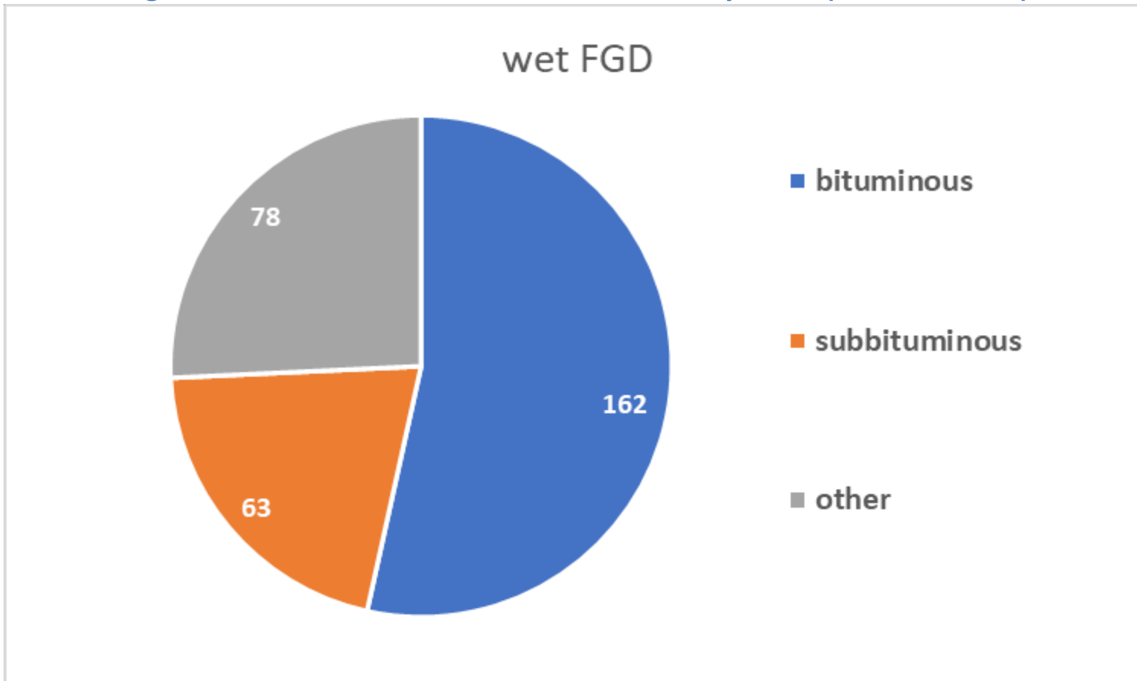
Figure 3. PM control technology in 2019[9]



[9] In this figure, "any type" is intended to mean that the total includes situations where the ESP or baghouse are installed individually or in combination as a COHPAC.

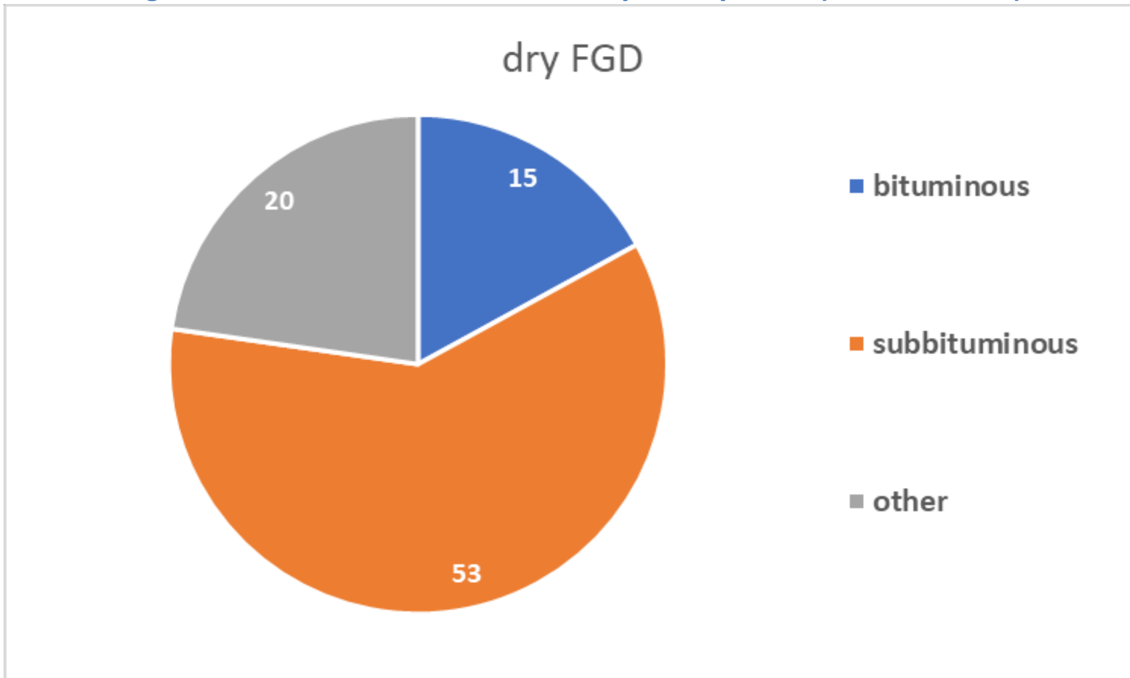
Because wet FGD systems primarily use a lower cost reagent (limestone) and achieve high levels of SO_2 capture, they are well suited for higher sulfur coals, which are bituminous. Figure 4 shows the distribution of coals used in wet FGD systems by the number of systems, and clearly most of the wet scrubbers are on bituminous coal fired units. "Other" coals include refined coals, lignite (a very small number) and coals in situations where the coal type was not indicated.

Figure 4. The coals that are used in wet FGD systems (# of coal units)



Because dry FGD systems all use lime, which is significantly more expensive than limestone, they are well suited for lower to medium sulfur coals, which are mostly subbituminous, but can be used on higher sulfur coals. Figure 5 shows the distribution of coals used in dry FGD systems by the number of systems, and clearly most of the dry scrubbers are on subbituminous coal fired units. "Other" coals would include refined coals, lignite (a very small number), or coals in situations where the coal type was not indicated.

Figure 5. The coals that are used in dry FGD systems (# of coal units)



Wet FGD systems

State-of-the-art wet FGD systems such as those used on electric utility boilers are capable of 99% or better SO_2 capture efficiencies, which would result in emissions rates below 0.05 lb SO_2/MMBtu assuming up to 5.0 lb SO_2/MMBtu uncontrolled levels. However, many facilities were constructed decades ago. Wet FGD systems typically offer slightly higher SO_2 removal efficiencies than dry FGD systems and are typically designed for one of two reagents – limestone or lime. State-of-the-art limestone and lime wet FGD systems are commonly used in large power plants, and the Electric Power Research Institute (EPRI) examined the potential for SO_2 removals over 99% on a consistent basis and found that such removal efficiencies are possible.[10]

[10] Electric Power Research Institute, Flue Gas Desulfurization (FGD) Performance Capability – High Efficiency Design and Operating Options, 1014171, March 2008

The most common form of wet FGD on coal power plants is limestone forced oxidation (LSFO) scrubbers. LSFO systems use limestone reagent, which is less expensive than other available reagents, and LSFO scrubbers also produce a gypsum by-product. Sparge air is introduced into the absorber slurry to oxidize calcium sulfite to calcium sulfate and produce gypsum. The gypsum by-product has commercial uses in production of wall board and Portland cement.

A significant number of wet FGD systems use lime rather than limestone. Lime is more reactive, and significantly more expensive, but the scrubber can be built to be somewhat smaller (and less costly) for the same emission reduction. There are very few wet FGD systems that use sodium-based reagents. Sodium-based reagents have the advantage of high water solubility, which makes the system simpler and less expensive, but can result in waste disposal issues due to the water-soluble product.

Figure 6 shows an example of an absorber vessel in an LSFO scrubber, again, the most commonly used wet FGD system. This is the heart of a wet FGD system, and although there is a lot of other equipment necessary to support wet FGD operation, the absorber vessel is where the pollutant capture occurs. This form of wet FGD is called a spray tower. There are other configurations as well, but the principles are generally the same. In the system depicted in this figure, flue gas enters the absorber vessel, it then passes upwards through gas distribution trays and injection nozzles that treat the gas with a limestone slurry, the gas then passes through mist eliminators to remove the moisture droplets, and then the cleaned gas passes out through the top.

Among the numerous factors that impact performance is liquid/gas interaction and mixing, and liquid-to-gas ratio. Liquid/gas interaction and mixing are impacted by the spray nozzle configuration, the use of baffles and other devices to improve liquid/gas interaction, and the number of spray levels. State-of-the-art wet FGD systems use engineering methods and equipment designs to improve FGD performance, and these will be explored more later in this report. Liquid-to-gas ratio is related to the treatment rate of the gas. It is important to ensure that the liquid-to-gas ratio is maintained evenly throughout the absorber vessel.