Analysis of the Illinois Coal Industry and Electrical Generation in Illinois

Flue Gas Desulfurization Task Force Report
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Executive Summary

The Flue Gas Desulfurization ("FGD") Task Force Act (20 ILCS 5120) created the FGD Task Force “to increase the amount of Illinois Basin coal use in generation units,” and to “identify and evaluate the costs, benefits, and barriers of new and modified FGD, or other post-combustion sulfur dioxide emission control technologies, and other capital improvements, that would be necessary for generation units to comply with the sulfur dioxide National Ambient Air Quality Standards (NAAQS) while improving the ability of those generation units to meet the effluent limitation guidelines (ELGs) for wastewater discharges and enhancing the marketability of the generation units' FGD byproducts.” The purpose of this document is to provide the background and analysis necessary for policy makers to arrive at informed decisions regarding Illinois coal use in Illinois electrical generation.

This report contains a history of the decline in the use of Illinois coal in electricity generation and the factors leading to this decline. These factors include regulations limiting sulfur dioxide ("SO₂") emissions from power plants, the economics of controlling the emissions of SO₂ in coal-fired electrical generating units (“EGUs”), and the use in Illinois power generation of low-sulfur coal from the Western United States.

This report also discusses a relatively new technology for SO₂ emission control whose proponents claim is extremely well-suited for application to coal-fired powered EGUs combusting Illinois coal, and the barriers to new technologies for emission control.
Background

The Clean Air Act Amendments of 1990 and the environmental regulations since then have led to a significant detrimental effect on the Illinois coal industry. A major component of these regulations is the reduction of sulfur dioxide ("SO\textsubscript{2}") emissions from coal burning power plants, as SO\textsubscript{2} is a pollutant that can be harmful to the human respiratory system and causes rain acidification. The sulfur content of coal mined in Illinois is high relative to other sources of coal and leads to higher emissions of SO\textsubscript{2} when combusted.

Power plants have had several options to comply with SO\textsubscript{2} limits in these regulations. Sources could install pollution control equipment such as flue gas desulfurization ("FGD") systems, purchase allowances to permit SO\textsubscript{2} emissions, switch to lower-sulfur sources of coal (primarily sub-bituminous coal from the Powder River Basin in Wyoming), or shut down the power plant. While some Illinois power generators did install pollution control equipment to allow them to continue to burn Illinois coal, the majority of the coal-fired generation in the state chose to fuel switch their fuel source to low-sulfur coal.

The Illinois utilities choosing to switch fuel sources were led by Commonwealth Edison Company ("Com Ed") which operated several coal power plants at the time, in addition to operating nuclear power plants in Illinois. Com Ed was having difficulty in receiving approval from the Illinois Commerce Commission ("ICC") in incorporating those nuclear plants fully into its rate base. Faced with the cost of hundreds of millions of dollars for scrubbers requiring approval by the ICC in a lengthy, contentious rate case, Com Ed opted for alternatives to meet the SO\textsubscript{2} limits. Com Ed determined it could meet the SO\textsubscript{2} limits by switching to low-sulfur Western coal. A key factor in this decision was an order from the ICC which approved transportation costs as part of the fuel costs meaning these costs were immediately recoverable in electric sales through the Fuel Adjustment Clause.

The impact on the Illinois coal industry was immediate and negative. Coal production declined 50% in 13 years, from 62 million tons in 1990 to 31 million tons in 2003. Since the mid-1990s, over 50 million tons per year of coal from Western states have been transported to be burned in Illinois power plants. Over the same period, 85% of the coal produced in Illinois has been exported for use out of state.

Since 1990, efforts to encourage Illinois power plants to switch to Illinois coal have faced two major hurdles, neither of which has been overcome. First, in 1991 the General Assembly enacted legislation that ordered the Illinois Commerce Commission to approve the construction of four scrubbers at unspecified power plants. The law was challenged by interests from the Western states as interfering with the free flow of interstate commerce in violation of the Commerce Clause of the U.S. Constitution. In 1995 the U.S. Court of Appeals in the Seventh District struck down the 1991 Illinois law. This precedent presents difficulties for the state in providing incentives or subsidies encouraging the use of Illinois coal in Illinois power plants.

Second, a law enacted in 1997 provided for the deregulation of electric generation in Illinois. Utilities no longer could request rate increases from the ICC to pay for the construction of new
power plants or large capital expenditures for existing power plants such as pollution control equipment. In many cases, investments in pollution control equipment such as FGD cannot be recouped or repaid while remaining competitive in Illinois’ deregulated electric market. Together these factors have led to the continued decline in Illinois coal production.

**Illinois Coal Industry**

Illinois sits atop much of the Illinois Coal Basin, and coal underlies 65% of the state. Illinois has the largest reported bituminous coal resources of any state in the U.S., totaling 38 billion tons of recoverable coal reserves. This represents one quarter of the nation’s bituminous coal reserves. The heating value of the coal reserves in Illinois is greater than for all the oil reserves of Saudi Arabia and Kuwait.

Currently, 85% of coal production in Illinois comes from two coal seams, the Herrin No. 6 and the Springfield No. 5, and there are 18 active coal mines in 13 counties in Illinois. These seams average from 4.5 to 8 feet in thickness, and the heating value is between 10,200 and 14,000 Btu per pound.

Between 1990 and 2007, Illinois coal production declined from over 61,000,000 tons to 32,000,000 tons mined per year. In that same period, consumption of Illinois coal in Illinois facilities declined from 15,598,500 tons per year to 5,690,400 tons per year. Also, in that same period, total coal consumption in Illinois from all sources (Illinois coal and non-Illinois coal) increased from approximately 25,000,000 tons to over 60,000,000 tons. Finally, in that same period, the percentage of coal used at Illinois plants that was mined in Illinois declined from 59% to 9%.

Of the 15 power plants in Illinois that are significant consumers of coal, 12 are located within 50 miles of an Illinois coal mine. However, use of coal mined in Illinois at these facilities has declined dramatically due to the environmental and economic factors discussed in this report.

Figure 1 is Illinois’ 2016 coal balance, showing the production of coal in Illinois, where that coal is shipped for use, and the quantity of non-Illinois coal used in the state.
Coal-Fired Electrical Generating Units in Illinois

There are currently 34 coal-fired electrical generating units (“EGUs”) operating in Illinois at 15 power plants. Twenty of those 34 units currently employ one of several technologies for post-combustion FGD. Figure 2 shows the location of the operating coal-fired EGUs in Illinois, and Table 1 lists those power plants and the methods used for reducing SO\textsubscript{2} emissions at those plants.
Figure 2. Location of Coal-Fired Electrical Generation in Illinois
Table 1. List of Coal-Fired Electrical Generation in Illinois

<table>
<thead>
<tr>
<th>Plant</th>
<th>Total Capacity</th>
<th>Low-Sulfur Coal/Control Equipment</th>
<th>Coal Source</th>
<th>Operator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baldwin – 3 Units</td>
<td>2032 MW</td>
<td>Dry Lime Scrubber</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Havana – 1 Unit</td>
<td>493 MW</td>
<td>Dry Lime Scrubber</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Hennepin – 2 Units</td>
<td>326 MW</td>
<td>Low-Sulfur Coal</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Coffeen – 2 Units</td>
<td>984 MW</td>
<td>Wet Limestone Scrubber</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Duck Creek – 1 Unit</td>
<td>484 MW</td>
<td>Wet Limestone Scrubber</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>ED Edwards – 2 Units</td>
<td>728 MW</td>
<td>Low-Sulfur Coal</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Joppa Steam – 6 Units</td>
<td>1364 MW</td>
<td>Low-Sulfur Coal</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Kincaid – 2 Units</td>
<td>1297 MW</td>
<td>Dry Sorbent Injection</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Newton – 1 Unit</td>
<td>748 MW</td>
<td>Low-Sulfur Coal</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Powerton – 4 Units (Pekin)</td>
<td>1673 MW</td>
<td>Dry Sorbent Injection</td>
<td>PRB</td>
<td>Midwest Generation</td>
</tr>
<tr>
<td>Waukegan – 2 Units</td>
<td>756 MW</td>
<td>Low-Sulfur Coal</td>
<td>PRB</td>
<td>Midwest Generation</td>
</tr>
<tr>
<td>Will County – 1 Unit (Romeoville)</td>
<td>534 MW</td>
<td>Low-Sulfur Coal</td>
<td>PRB</td>
<td>Midwest Generation</td>
</tr>
<tr>
<td>CWLP – 4 Units (Springfield)</td>
<td>567 MW</td>
<td>Wet Limestone Scrubber</td>
<td>Illinois</td>
<td>Municipal</td>
</tr>
<tr>
<td>Prairie State – 2 Units (Marissa)</td>
<td>1664 MW</td>
<td>Wet Lime Scrubber</td>
<td>Illinois</td>
<td>Consortium of Rural Electric Cooperatives</td>
</tr>
<tr>
<td>SIPC Marion - 2 Units</td>
<td>312 MW</td>
<td>Fluidized Bed Limestone/Wet Lime Scrubber</td>
<td>Illinois</td>
<td>Rural</td>
</tr>
</tbody>
</table>
As can be seen in Table 1, the majority of Illinois’ coal-fired generation capacity is combusting coal from the Powder River Basin (“PRB”) located in the Western states of Wyoming and Montana. The following sections of this report provide a more detailed analysis of the environmental and economic factors that have led to these fuel choices. As prefaced in the Background section of this report, the high sulfur content of Illinois coal remains the primary barrier to its use in power generation in Illinois and elsewhere.

Air Quality Issues and Regulations Related to Sulfur Dioxide Emissions

While the aforementioned Clean Air Act Amendments were aimed at SO2 emissions and their impact on acid rain, more recent regulations for SO2 emissions have been aimed at impacts on human health and other environmental quality impacts. Acid rain is no longer a significant consideration in limiting emissions of SO2.

Currently, the primary consideration related to SO2 emissions from coal-fired EGUs is meeting the National Ambient Air Quality Standards (“NAAQS”) that limit allowable concentrations of pollutants in ambient air in any area that is accessible to the public.

The NAAQS for SO2, established in 2010, is 75 parts per billion, assessed on a 1-hour basis. Areas of concern for the SO2 NAAQS are generally localized near large emitters of SO2, such as large coal-fired facilities. In 2015, Illinois adopted new rules for reducing SO2 emissions in two areas of the State that were determined to be in nonattainment of the SO2 NAAQS. Both of those areas were impacted by SO2 emissions from coal-fired power plants, and the adopted rules contained new emission limits for those plants. Currently, those nonattainment areas have SO2 concentrations that meet the NAAQS, and will be redesignated to attainment of the standard in the near future.

SO2 also reacts in the atmosphere with other pollutants, such as ammonia, to form fine particles that are regulated as a different pollutant known as PM2.5, or particulate matter with particles being 2.5 micrometers or less in diameter. PM2.5 is known to have human health effects, including respiratory and cardiovascular impacts, and there is also a NAAQS for PM2.5. The PM2.5 NAAQS, established in 2012, is 12.0 micrograms per cubic meter (µg/m3) on an annual basis, and 35 µg/m3 on a 24-hour basis. All areas of Illinois are currently monitoring PM2.5 concentrations that are in attainment of these standards.

Once PM2.5 is emitted or formed in the atmosphere, it can also travel to other areas and other states. This is generally called pollutant transport. Transport of PM2.5 can contribute to nonattainment of the NAAQS in other areas or other states, and also contributes to visibility impairment or hazy atmospheric conditions. Control of SO2 emissions to limit formation of PM2.5 is a key goal of the Regional Haze Rule. The Regional Haze Rule is aimed at reducing visibility impacts in National Parks and other areas designated by the USEPA as “Class I Areas” under the rule. The Regional Haze Rule was designed to return all Class I Areas in the United States to natural visibility conditions by the 2065. Illinois is currently meeting all of its obligations related to the Regional Haze Rule.
Federal Regulations Limiting SO₂ Emissions

Emissions of SO₂ in Illinois and the United States, in general, have been drastically reduced since the 1990s. Much of this reduction is a result of a series of federal “cap and trade” programs that continue today. In a cap and trade program, a total SO₂ emissions budget, in tons, is set for an entire region of the United States, and that number of one-ton emission allowances is created. At the end of a year, an emission source, such as a power plant, must hold a number of allowances equal to its emissions in that year. These allowances are allocated to sources based upon their historical need for them at the beginning of each year. The allowances can be traded between sources to meet their emissions in that year. This cap and trade system encourages control of emissions in the most economically efficient manner. A source may choose to control emissions using control equipment, such as FGD where it is economical to deploy, or a source can simply purchase allowances to cover its emissions. A source with SO₂ controls can offset the cost of those controls by selling excess allowances that are not needed due to the controls at that source. This incentivizes the installation of control equipment where it is most economically viable. In a cap and trade program, the availability and price of allowances may fluctuate, but the total emissions in the affected region can be guaranteed to be less than the emission budget. These cap and trade programs have been very successful in ratcheting down SO₂ emissions in the Eastern United States since 1995.

The Acid Rain Program, beginning in 1995, was designed with a budget of 8.95 million tons of SO₂. At the time, this budget amounted to a reduction of approximately 7 million tons of SO₂ annually. The next iteration of SO₂ cap and trade program was the Clean Air Interstate Rule (“CAIR”). CAIR began with an emission budget of 3.6 million tons in 2009, which was reduced in Phase II to 2.5 million tons. The current SO₂ cap and trade program in place is the Cross-State Air Pollution Rule (“CSAPR”), which began with an emission budget in line with CAIR, but starting in 2017, the SO₂ emission budget is set at 1.4 million tons. Thus, in the years between 1995 and 2017, SO₂ emissions from affected facilities in the Eastern United States have been reduced from approximately 17 million tons annually to less than 1.4 million tons annually.

The reduction in SO₂ emissions from these programs was achieved in the power sector by a combination of pollution control installations, the use of low-sulfur PRB coal, and the retirement of less economically viable and older coal-fired facilities. In recent years, as reductions have occurred, the cost for emission allowances has also plummeted. This has led to less incentive to install FGD, and a greater incentive to use low-sulfur coal and to purchase allowances if necessary.
As can be seen in Figure 2, allowance prices remained steady in the range of $150 to $200 per ton until 2004. Allowance prices then increased sharply due to the uncertainty of the impact of lower budgets when CAIR was proposed. This meant that power plants that could achieve control costs that were lower than those allowance prices could be incentivized to install controls. However, since that time allowance prices have continued to decline precipitously to $2 a ton or lower today. At such a low price, the federal trading program is no longer an incentive for the installation of FGD.

**State Regulations Limiting SO\(_2\) Emissions**

Illinois regulations aimed at attaining the NAAQS for SO\(_2\) near power plants and other sources of SO\(_2\) emissions can be found in Title 35 of the Illinois Administrative Code (“35 IAC”) in Part 214.603. These limits are source-specific and are in terms of pounds of SO\(_2\) emitted per hour to ensure that SO\(_2\) concentrations around those sources remain below the NAAQS. These rules are bringing all areas of Illinois into attainment of the NAAQS for SO\(_2\).

Additional limits for SO\(_2\) from power plants are found in 35 IAC Part 225 in the Multi-Pollutant Standard (“MPS”) and Combined Pollutant Standard (“CPS”). The MPS and CPS contain rate-based SO\(_2\) limits in terms of pounds of SO\(_2\) per million Btu (“lb/mmBtu”) of heat input to a unit. These limits are evaluated on the basis of average emissions from an entire fleet of EGUs controlled by a single owner or operator. Current emission limits in the MPS and CPS range from 0.11 lb/mmBtu to 0.23 lb/mmBtu. These emission rates are much lower than can be achieved from the uncontrolled combustion of Illinois or PRB coal, but the emission averaging means that not all units in a given fleet need additional SO\(_2\) control equipment for that fleet of units to comply with the average limits.

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1 2011 average SO\(_2\) allowance prices at auction were $2.81 and have not exceeded $1 since then.
These limits are currently a more significant driver for SO₂ emission control in Illinois than the federal trading programs. These limits apply to all of the units listed in Table 1 that are currently operated by Vistra and Midwest Generation, and also account for all of the facilities on that list burning PRB coal.

**Compliance Measures for Meeting SO₂ Limits**

As noted above, SO₂ emission limits applied to units, and to fleets of units, range between 0.11 lb/mmBtu and 1.2 lb/mmBtu. Uncontrolled emissions from coal combustion range from 0.5 to 5.0 lb/mmBtu depending on the source of the coal and other factors.

The bulk of emission reductions for these power plants is the use of low-sulfur coal from outside of Illinois and post-combustion FGD.

**Comparison of Illinois Coal and PRB Coal.**

As stated previously, a major factor in the decline in Illinois coal use has been the availability and cost of low-sulfur PRB coal. A comparison of Illinois coal to PRB coal and their respective suitability for use in Illinois EGUs must include the heating value of the fuels, fuel costs, transportation costs, and the sulfur content of each coal type. The following comparison uses data from the Energy Information Administration (“EIA”) and contains approximate values that can be applied generally to Illinois coal and PRB coal. These values vary depending on more specific locations from which a coal has been produced.

Illinois coal is a bituminous coal with a heating value around 11,800 Btu per pound. PRB coal is a subbituminous coal with a heating value around 8,800 Btu per pound. This amounts to an average heating value for Illinois coal that is 34% greater than PRB coal.

Recent spot prices for Illinois coal from EIA have been around $32 per ton, while spot prices for PRB coal have been around $12 per ton. However, the delivery cost to transport PRB coal to users in Illinois is around $21 per ton, increasing the delivered price of a ton of PRB coal to around $33 per ton. As such, Illinois coal and delivered PRB coal are roughly equal in terms of cost in dollars per ton.

The major factor in the use of PRB coal rather than Illinois coal is the sulfur content of each fuel. SO₂ emissions from uncontrolled combustion of Illinois coal are in a range between 3 and 5 lbs/mmBtu, while emissions from combustions of uncontrolled PRB coal are in a range between 0.5 and 0.8 lb/mmBtu. It is this difference in sulfur content that outweighs the heating value advantage of Illinois coal in most economic considerations. Many power plants can comply with SO₂ regulations by using PRB coal without the capital expenditures and operating costs associated with installing FGD pollution control equipment. FGD systems are unquestionably necessary when burning Illinois coal. Common FGD technologies and the costs associated therewith are discussed in the following section.
Technology for Controlling SO\textsubscript{2} Emissions

In Illinois and elsewhere, the most common and effective compliance measures for reducing SO\textsubscript{2} emissions from coal combustion is the use of low-sulfur coal and the use of post-combustion FGD systems.

In general, FGD systems remove SO\textsubscript{2} from combustion gases by using an alkaline reagent to absorb the pollutant and produce a solid compound that can be removed. Three different types of FGD are typically used today to reduce SO\textsubscript{2} emissions from EGUs: wet scrubbers, dry scrubbers, and dry sorbent injection (“DSI”).

Wet scrubbers use a wet slurry, usually of limestone or lime, to react with SO\textsubscript{2} in the flue gas. This reaction of the calcium in the slurry and the SO\textsubscript{2} in the flue gas forms gypsum (CaSO\textsubscript{4}) that can be removed, but must be dewatered, creating wastewater from the process. Wet scrubbing is the most expensive type of FGD due to the high capital cost of installation, but is also often the most appropriate type for large coal-fired boilers. Wet scrubbing also achieves the highest SO\textsubscript{2} control efficiencies, typically in a range of 90 to 95%, but potentially up to 99%. Additional annual operation and maintenance costs include the cost of lime or limestone sorbent, the energy required to operate the control, and costs associated with wastewater treatment.

Dry scrubbers, or spray dryers, use a sorbent slurry similar to those used in wet scrubbers to react with SO\textsubscript{2} in the flue gas, however, in a dry scrubber the flue gas heat evaporates all of the added water in the slurry, and the salts formed by the SO\textsubscript{2} and sorbent are collected downstream by a particulate control device such as an electrostatic precipitator (“ESP”) or a fabric filter baghouse. Dry scrubbing typically achieves SO\textsubscript{2} control efficiencies in a range of 80 to 90%, but can also achieve higher efficiencies. Dry scrubbing is generally less expensive than wet scrubbing because handling and treatment of wet waste products is not required, but like wet scrubbing, operation and maintenance costs include expenditures for sorbent and the energy required to operate the control.

DSI systems remove SO\textsubscript{2} by injecting a dry sorbent directly into the combustion chamber, into the flue gas duct ahead of the particulate control, or into an additional reaction chamber designed specifically for sorbent injection. DSI systems are often the lowest-cost option for SO\textsubscript{2} control due to lower installation costs, but typically only achieve control efficiencies in a range between 50 and 80%. DSI is effective for units of any size, but additional sorbent is required for greater SO\textsubscript{2} removal. Costs for DSI are heavily dependent upon the cost and usage rate of the sorbent, and can vary greatly due to the size of a unit, the desired control efficiency, and a number of other factors specific to any given power plant.

Economics of FGD

The most relevant measures for the cost of SO\textsubscript{2} control by FGD are the costs in dollars per ton of SO\textsubscript{2} removed, and the annualized costs of installing and operating an FGD system. The dollars per ton of SO\textsubscript{2} removed figures are useful in comparison to prices for emission allowances. Annualized costs of controls include capital costs amortized over the life of the system and the
operation and maintenance costs associated with the control, and provide an understandable estimate of the actual costs to a power plant operators. Estimates for costs have been taken from USEPA information, and the following estimates are based on a unit with a capacity of 500 megawatts. Coal-fired units in Illinois range between 78 and 800 MW, but a 500 MW unit could be considered a unit of typical size in Illinois for the purposes of these estimates.

Wet scrubbing system capital costs range from $50 to $125 million, and annualized costs range from $10 to $25 million annually. Control costs are in a range of $200 to $500 per ton of SO2 removed.

Dry scrubbing system capital costs range from $20 to $75 million, and annualized costs are also range from $10 to $25 million annually. Control costs are in a range of $150 to $300 per ton of SO2 removed.

DSI system capital costs range from $3 to $15 million, but as previously stated, control costs and annualized costs are heavily dependent upon factors specific to the power plant and their target control efficiency.

Capital costs for wet and dry scrubbers in recent years have proven to economically discourage plant owners from installing those FGD types. Recent installations of FGD in Illinois have been the lower-cost DSI systems applied to units that are also burning low-sulfur coal to meet Illinois SO2 regulation limits, as well as to control other acid gases. Because allowance prices have fallen to the $2-per-ton range, and cost of control with FGD remains in the $150 to $500-per-ton range, the federal trading program is no longer an incentive to install controls. Additionally, with annualized costs in the range of $10 to $25 million, the use of low-sulfur coal from outside Illinois in lieu of installing and operating controls outweighs the advantage Illinois coal would provide with its higher heating value.

**Alternative SO2 Control Technology**

At the October 10th meeting of the FGD Task Force, a presentation was made by representatives of Jiangnan Environmental Technology Inc. ("JET"), a company that reports it has been installing and operating ammonia-based FGD systems overseas. According to JET, these ammonia-based FGD systems have many advantages over conventional limestone/lime wet scrubbers and can increase revenue at a power plant through the sale of the byproducts of the systems. JET representatives suggested that use of higher-sulfur Illinois coal in their systems was actually preferable to low-sulfur coal because it would produce more byproduct which is potentially saleable.

According to JET, advantages of ammonia-based FGD systems include: SO2 control efficiencies of 99% or greater; no wastewater or solid waste; lesser power consumption by the controls and thus lower operating costs; and additional profits through the sale of ammonia sulfate as a fertilizer.
The company’s business model involves financial support for the cost incurred by EGU owner related to installation of the technology, for the costs associated with the packaging and sale of the fertilizer byproduct, and for operation of the control at the plant. JET posits this arrangement provides for essentially no-cost control of SO₂ emissions in addition to a share of the revenue to the plant from the sale of the byproduct.

JET does not currently operate any ammonia-based FGD systems in the U.S., however, the company apparently has installed the technology in over 150 projects worldwide, and claims that the technology is mature and suitable for use in the U.S. Issues of concern for installation of this technology in the U.S. are the permitting difficulties presented by a third-party control operator, potential additional emissions of ammonia and particulate matter, ensuring that there are indeed no issues requiring water permitting, and the issues involving accumulation of byproduct in the event it is not marketable.

Also at the October 10th meeting of the FGD Task Force, an FGD Task Force member representing City Water Light & Power in Springfield presented information regarding new control technologies from the perspective of a power plant operator. The presentation included concerns for power plant operators associated with risk in meeting capacity requirements, compliance risk (since the EGU owner/operator remains responsible for meeting emission limits even if the FGD owner is contractually running the control device), risk from future regulations that could apply to new technologies, permitting details (the owner/operator would be responsible for the permit of a control device being run by another company), and the ultimate liability of the plant operator for projects at their plants (such as a situation where the company responsible for the control device were to go out of business, all liability for compliance and future operation of those controls would run to the power plant operator). It was suggested that grants to incentivize installation of new technologies may be needed to mitigate some of these risks, and other aspects would require cooperation with government bodies for permitting and regulatory issues.

Conclusions

This section will require input from Task Force members to decide what they believe should be the overall message of the report given the information above.