Pollution Control in the U.S. Power Sector: New Requirements, Costs, and Decisions for Electric Utilities

R. Raufer

Introduction

There has recently been considerable debate in the U.S. about whether IGCC represents "Best Available Control Technology" for coal combustion, given its ability for lowering emissions and potentially separating CO_2 to address global warming concerns. Coal-fired power generating units are now enjoying a renaissance in the U.S., and approximately 150 new plants are now on the drawing boards[1], after more than twenty years of power plant construction focused primarily on natural gas fired units. Existing units within the country are also being subjected to more stringent pollution control requirements for particulate, sulfur dioxide and oxides of nitrogen emissions, and control of mercury emissions is also now being mandated.

The market-based nature of the regulatory requirement has changed the decision-making process for pollution control at U.S. utilities, however, introducing flexibility for utilities and subsequently lowering costs for electricity consumers. This paper addresses these topics, outlining the new pollution control requirements for U.S. power plants; the nature of the pollution control options available to meet such requirements, and the costs of such pollution control technology; the effects of such costs on the pricing of electricity in the country; the evolution of market-based decision-making for pollution control at U.S. utilities; and the "lessons learned" from the U.S. experience that might be relevant for China.

Pollution Control Requirements For U.S. Power Plants

As in any country, the pollution control requirements for power plants that have evolved in the United States are a complex mix of legislation, regulatory agency mandates, governmental exhortations, lawsuit challenges, non-compliance enforcement strictures, agreements with non-governmental pressure groups, and a host of other governmental/industry institutional arrangements and agreements. Every state within the U.S. has its own "State Implementation Plan" (SIP) which allows it to follow its own regulatory path (as long as it meets the minimum requirements mandated by U.S. law)—so similar power plants in different states may have different pollution control requirements. During the 1970s and 1980s, most of the pollution control efforts in the power sector focused on sulfur dioxide and particulate controls in order to meet localized air quality goals in the National Ambient Air Quality Standards (NAAQS). In 1990, however, new air quality legislation introduced two major shifts: 1) a new acid rain control program designed to address the "total loading" of sulfur dioxide; and 2) a focus on NOx control to achieve the ozone NAAQS, and to reduce acidification. Particularly important for power plants was the fact that the acid rain control program introduced a pioneering new market-oriented manner of addressing pollution (as discussed below), although it included traditional "command/control" requirements for NOx emissions from power plants as well.

Subsequent to these 1990 legislative changes, EPA has introduced a series of regulatory programs which have had a major impact on the power industry's pollution control program. Most significant are:

- *The "NOx Budget."* This was introduced in the Northeastern U.S. in the late 1990s, and like the acid rain control program, it introduced the idea of utilizing markets to achieve the ozone NAAQS, but this time for NOx. Unlike the nationwide acid rain program, it addressed a smaller regional area, and was a summertime (May 1 – September 30) rather than full-year market, since ozone violations tended to occur during the summer.
- *NOx "SIP Call".* This expanded the NOx control area from the Northeast U.S. to most of the eastern states (22 states) in order to achieve the ozone NAAQS, because of the long range transport of pollutants.
- *Ozone NAAQS Revision.* The 1997 revision of the ozone standard shifted from a one hour to an eight hour averaging time, and introduced a new "concentration-based" approach which is based upon the three year average of the fourth-highest daily maximum 8-hour concentration, expanding the non-attainment areas requiring further controls.
- *Particulate NAAQS Revision.* A similar revision for particulate added a new standard for particles with a diameter $\leq$ 2.5 microns, to address health impacts. In addition to changing non-attainment areas, it also had the effect of shifting attention to NOx and SOx gas control, since these smaller particles are products of combustion, rather than mechanically generated.
- *Clean Air Visibility Rule (CAVR).* This EPA Rule is designed to improve visibility in 156 national parks and wilderness areas in the country, and requires states—in conjunction with federal agencies such as the National Park Service and the U.S. Forest Service—to develop control plans (utilizing source-specific BART) to address pollutants causing visibility impacts.
- *Revised NSR.* In 2002, the EPA revised the requirements for determining how power plants would trigger New Source Review for plant modifications needing further controls, and has subsequently proposed changes to bring the requirements into compliance with court rulings.
- *Clean Air Interstate Rule (CAIR).* Adopted in March 2005, this rule is designed to control power plant SO_2 emissions by more than 70% and NOx emissions by

more than 60% from 2003 levels in 28 eastern U.S. states (and DC), in order to address attainment of both ozone and particulate standards. It also uses the market-based allowance approach, and the first stage of controls will begin in 2009 for NOx and 2010 for SO_2. An EPA official has called this rule "one of the top three most significant actions in EPA history."[2]

- *Clean Air Mercury Rule (CAMR).* This rule, also adopted in March 2005, calls for a 70% emissions reduction of mercury from coal-fired power plants in the U.S., in a two step process. The first step, in 2010, will essentially rely on CAIR controls, while the second, in 2018, will require additional technology. This rule too will employ markets, with allowances of ounces of Hg.
- *"Clear Skies" legislation (proposed).* First proposed in 2002 (and re-introduced in 2003), this Bush Administration legislative proposal would have had a nationwide reduction program for NOx, SOx and Hg. Because it was not successful, EPA subsequently promulgated the CAIR and CAMR programs in 2005. Various other multi-pollutant legislative proposals—some addressing CO_2, some not—have also been introduced in the interim period.

The point of this listing is not to provide detailed information about power plant pollution control requirements, but rather to show that: a) the levels of pollution control required for both new and existing power plant facilities in the U.S. is significant, and becoming increasingly stringent over time; b) there is an increasing focus on regional and national control programs, even to address localized air pollution; c) the programs are increasingly requiring multi-pollutant (i.e., SOx, NOx, Hg, and $PM_{2.5}$) control efforts, and CO_2 is becoming likely as well; d) the pollution control decision-making at individual facilities is complex (for managers) and administratively complicated (for regulators); and e) as discussed below, the pollutant control decision is now significantly affected by emissions trading and market-oriented pollution control decisions.

Pollution Control Options and Costs

EPA has a range of models that can be used to estimate air quality impacts, retail electricity pricing, economic benefits, and a host of other regulatory concerns, but the core of its analyses for the control programs noted above is the Integrated Planning Model (IPM). IPM is a dynamic linear programming model that determines the least cost method of meeting energy and peak electrical demand requirements over a specified time period (typically through 2030), in regional power markets throughout the country. It does so subject to a variety of constraints, including capacity factor, emission, transmission, and fuel supply constraints. Its 2004 Base runs considered 13,814 existing generating units in the country,[3] including fossil-fuel fired units, as well as nuclear and renewable options (e.g., wind, solar, geothermal, etc.). The model can add potential (i.e., new) facilities, as well as consider unit retirements, repowering and retrofit options. Of particular interest for the EPA programs noted above are the key retrofit pollution control technologies employed by the power sector to achieve emissions reductions.[4]

For sulfur dioxide controls, the IPM employs limestone forced oxidation (LSFO) scrubbers on coal-fired units (100 MW and larger) burning bituminous coal with 2% (wt.) or higher sulfur content. Magnesium enhanced lime (MEL) scrubbers are employed on units between 100 and 550 MW, burning bituminous, sub-bituminous or lignite coal with less than 2.5% S. Lime spray drying (LSD) scrubbers are employed on larger units (550 MW or greater) burning bituminous, sub-bituminous or lignite coal with a sulfur content between 0.4 and 2%. EPA has developed cost and performance equations that are a function of such parameters as heat rate, capacity and sulfur content, and employs these for specific applications. For example, the capital costs ($/kW)[5] for sulfur dioxide control range from $118/kW for a large unit with a low heat rate employing LSD to $481/kW for a small facility with a high heat rate utilizing LSFO.

NOx combustion control options have similar cost equations developed to address boiler types, coal types, and controls already in place, and can then add additional combustion controls accordingly, also utilizing a scaling factor.Selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are options for post-combustion controls for NOx, with the former providing 90% reductions for coal-fired units (down to 0.06 lb/mmBtu), and the latter 35% reductions. Information was updated for the 2004 Base Case runs, but capital costs for SCR were $100/kW, and SNCR were in the $17-20/kW range, again subject to a scaling factor.

The Hg removal analysis was much more complex, since it depends upon the coal being burned, and much of the control will be derived as a co-benefit of the CAIR pollution control activities. The model developed "emission modification factors" for the specific burner type and configuration of SOx, NOx and particulate control technologies, and these factors also vary as a function of coal type burned. For example, research has determined that for bituminous coals, "SCR systems have the ability to convert elemental Hg into ionic Hg and thus allow easier capture in a downstream wet-FGD scrubber,"[6] and these effects were reflected in the model. Similarly, the cost of activated carbon injection (ACI) retrofits depends upon the desired Hg removal rate, the coal type, the sulfur content of the coal, and pre-existing SOx, NOx and particulate control devices; accordingly, 26 different cost functions were developed to enable the model to address these parameters. For a representative 500 MW, 10,000 Btu/kWh heat rate unit, the capital costs for 90% Hg removal ranged from $1.32/kW to $72.28, depending upon coal type and control technologies already in place.

When these technologies and costs were used to analyze the impacts of CAIR, EPA's analysis determined that an additional 37 GW of FGD scrubbers would be added by 2010 to power facilities, and 14 GW of SCR.[7] The annualized costs of the control were determined to be $3.6 billion in 2015. Since the annualized benefits in the same year were estimated to be in the $100 billion dollar range,[8] EPA believes that the regulations easily pass any cost/benefit criteria.

EPA suggests that the net present value of all outlays between 2007 and 2025 is about $50 billion, with about half of that in capital investment. An Edison Electric Institute survey (2005) of electric utilities found more than $40 billion in planned capital investments and other environmental expenditures over the next 10-12 years, with most of that targeted at air quality requirements.[9]

The electric utility industry is not fully convinced about EPA's benefits estimates—they note that "recent research suggests that any health effects attributable to $PM_{2.5}$ are not related to power plant-related sulfates and nitrates"[10]—and suggest that other pollutants and substances in $PM_{2.5}$ may play an important role. However, the industry "advocates public policies that are protective of public health and is prepared to make additional reductions in power plant emissions of SO_2, NOx and Hg."[11] It is worried however, that individual states may not adopt the market-oriented trading approaches that EPA has developed, and instead will take a more prescriptive approach—particularly for mercury control.

Effects on Electricity Prices

The electric utilities will obviously seek to recover the costs of these pollution control investments from the ratepayers who purchase electricity, but the cost-recovery analysis is complicated by the complex nature of utility regulation within the U.S., which primarily takes place at the state level. Some states will allow full cost recovery for environmental compliance expenditures, while others will include such items in general rate case increases—which often take considerable time and introduce considerable uncertainty for the utility. Some states have deregulated retail markets, and these generators may be forced to recoup environmental capital investments from the market-clearing prices above their variable costs. There is a distinct possibility that some compliance costs may not be recovered in this case, resulting in financial stress on the utility or IPP.[12]

EPA has analyzed the expected impact of CAIR on electricity rates and found that—despite such large environmental investment—overall regional retail electricity rates were only expected to be 2-3% higher.[13] Consumers in the east central states (OH, MI, IN, KY, WV, and PA) would see slightly higher increases, however, in the 3.5-6% range.[14] The incremental rate increases were expected to be 1.2 mills/kWh in 2010, 1.6 mills/kWh in 2015, and 1.1 mills/kWh in 2020 throughout the region.[15]

These are relatively modest increases, given other factors which are currently affecting electricity pricing. Although utilities spent $3.2 billion last year on environmentally related capital investments (more than 2½ times the figure in 1999),[16] fully 95% of costs increases over the past five years are associated with fuel and purchased power costs.[17] Both coal and natural gas, fuels responsible for more than 70% of U.S. power generation, have experienced two and even three digit percentage price increases in recent years.[18] Operating cash flows of U.S. utilities in 2005 were insufficient to cover their capital expenditures and operating costs, resulting in a $10 billion shortfall.[19] There is a considerable need for capital investment in the U.S. utility sector to meet ever increasing electrical demand, to upgrade transmission capabilities, to deliver higher quality power necessary for digital loads, and to meet distribution problems associated with hurricane, flood, and storm damage. Coal-fired power plants also account for approximately 33% of U.S. CO_2 emissions, so the industry is keeping a watchful eye on potential legislation and regulatory requirements in that area which might similarly demand considerable amounts of capital investment.

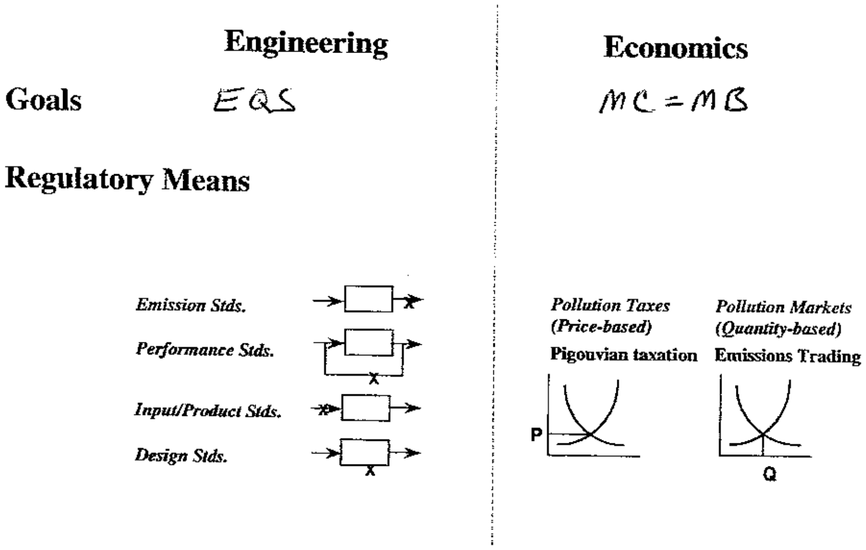
Market-based Decision Making for Pollution Control

By utilizing environmental markets in its acid rain, NOx Budget, CAIR, CAMR and other regulatory programs, US EPA is able to provide utilities with considerable regulatory flexibility while at the same time delivering environmental quality at a lower cost—and thus keep the increases in electricity rates low for consumers and ratepayers.

As mentioned above, utilities worry that states will ignore EPA's market approach. The reason utilities are worried is that, while the pollution control costs are certainly substantial, they would likely be much higher if they did not contain the market-oriented provisions noted earlier. In analyzing the impacts of mercury control under CAMR, for example, analysts have estimated that the present value of the costs associated with the market approach over the "command/control" requirement over the period 2005-2025. Using utility estimates, the present value of costs for command/control technology is approximately $15.4-20.7 billion, while under the market approach costs will be $3.4-5.5 billion.[20] Thus costs would be many times higher, and market savings are on the order of $15 billion.[21]

It is important for engineers to understand the manner in which such market-oriented thinking evolved within the U.S. regulatory system over the past several decades, since engineers and economists tend to view pollution control very differently (see Figure 1). Engineers typically view any process in terms inputs and outputs, with both (and the process design itself) subject to control. They then utilize technology-based standards based on such ideas to meet environmental quality goals. This is the traditional regulatory view incorporated into the 1970 Clean Air Act. Economists, however, believe that the environmental goal should be at the point where the marginal costs of control equal the marginal benefits, and offer two methods to get to that point—one based on prices (pollution taxes) and one based on quantities (emissions trading). The U.S. system began solely with the engineering approach, but then began to modify its regulatory system in the mid-1970s when it introduced marginal cost thinking in a "controlled" trading program (see Figure 2). This kept all of the characteristics of the engineering approach, but allowed firms that had very high marginal costs to avoid them by using an imaginary "bubble" over the facility (or facilities) and then trading emissions within the bubble.

Figure 1. Engineering vs. Economic Worldviews



It also utilized the trading program to address new sources in polluted areas, requiring them to "offset" their new (added) pollution. This was thus an economic approach grafted on to an engineering-based regulatory program, making it more efficient. Legislation in 1990 introduced the full-scale economic approach (i.e., the quantity-based approach) to control acid rain, as shown in Figure 3. Note that the acid rain control program kept the same engineering/economic hybrid system to address localized air quality for sulfur dioxide, but added the economic approach for total pollutant loading. Later, these markets have expanded, as noted earlier, to include NOx and Hg as well. These ideas have now received international attention. Figure 3, for example, provides the same basic trading template as that subsequently employed in the Kyoto Protocol. Project-based credit trading (utilizing CERs and ERUs instead of ERCs) occurs under the Clean Development Mechanism and Joint Implementation, while budget-based trading for Annex I countries occurs under international emissions trading provisions in Article 17 (utilizing AAUs instead of allowances).

Figure 2. U.S. Emissions Trading Program – mid 1970s

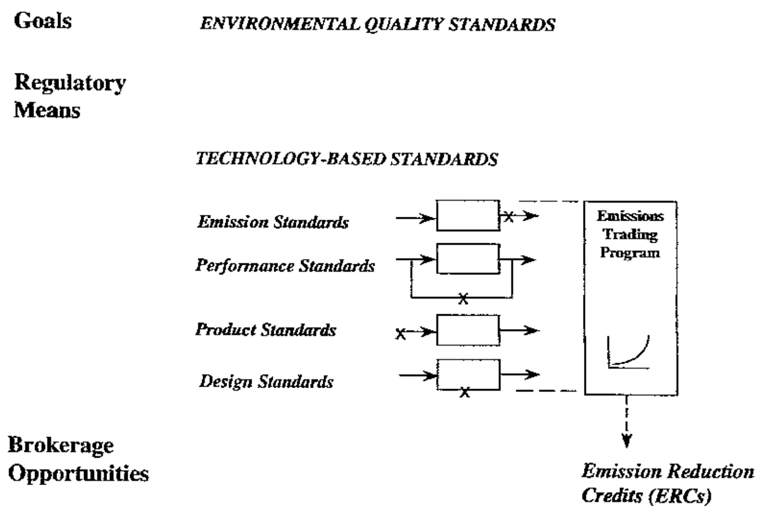
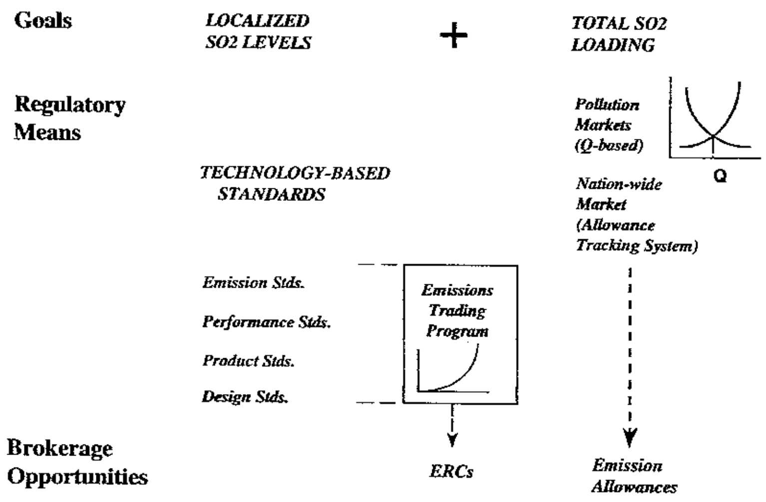


Figure 3. U.S. Acid Rain Control Program – 1990



Relevance for China

China is certainly cognizant of the very important characteristics associated with emissions trading and the use of such markets, and has introduced a number of pilot projects—some in conjunction with U.S. EPA[22] and the ADB,[23] and most recently in Hong Kong.[24]

As noted above, the U.S. developed its market-based approach over several decades, first employing an engineering-oriented "command/control" approach, and gradually modifying that over time to incorporate economic instruments. The environmental markets rely heavily upon the institutional infrastructure that was established to address the engineering approach. China's government has much more experience with price-based economic instruments, in the form of a pollution levy system, rather than the quantity-based market approach employed in the U.S. If properly structured and reformed, the price-based approach could deliver much of the economic efficiency found in the U.S. regulatory markets, and the distributional effects would also be more attuned to China's existing political and regulatory system than those associated with newly constructed externality markets. China should continue to gain experience with emissions trading systems in the international arena, however, including the Clean Development Mechanism. This is a very useful mechanism, because it introduces transparency and environmental accountability into energy project development, and relies upon an international system for validation and verification of credits. Such a combined approach—utilizing both price (domestic) and quantity (international) instruments—could thus help China meet its significant air pollution control requirements in the energy sector in a cost effective manner.

REFERENCES

[1] These represent an investment of $137 billion; see Madsen, T. and Sargent, R., *Making Sense of the 'Coal Rush': The Consequences of Expanding America's Dependence on Coal*, U.S. PIRG Education Fund and the National Association of State PIRGs, July 2006.

[2] Holmstead, J., "A Multipollutant Approach to Emissions Reductions," *Environmental Manager*, August 2005, p. 7.

[3] These were aggregated into 2053 "model" plants. See p. 2-6 of, EPA 430-R-05-011, Washington, DC, September, 2005.

[4] The following pollution control technology data were based upon information in Chapter 5 in EPA 430-R-05-011, September, 2005.

[5] In 1999 dollars.

[6] EPA 430-R-05-011, Sept., 2005, p. 5-11.

[7] EPA- 452/R-05-002, March, 2005, p. 7-9.

[8] $86.3 billion to $101 billion, depending upon the discount rate employed. See EPA-452/R-05-002, March, 2005, p. 1-1.

[9] Basheda, G. et al, *Why Are Electricity Prices Increasing?: An Industry-Wide Perspective,* prepared for The Edison Foundation, Washington, DC, June, 2006, p. 74.

[10] McManus et al, "The Utility Industry: Reactions to EPA's Clean Air Interstate and Clean Air Mercury Rules," *Environmental Manager,* August 2005, p. 11.

[11] Ibid., p. 12

[12] Basheda, G. et al, p. 75.

[13] EPA- 452/R-05-002, March, 2005, p. 7-13.

[14] Ibid, p. 7-14.

[15] Ibid., derived from data in Table 7-9 on p. 7-14.

[16] Basheda et al, p. 74.

[17] Ibid., p.2.

[18] Ibid.

[19] Ibid., p.4.

[20] Gayer, T., and Hahn, R., *Designing Environmental Policy: Lessons from the Regulation of Mercury Emissions,* Regulatory Analysis 05-01, AEI-Brookings Joint Center for Regulatory Studies, Washington, DC, December 2004 (revised April 2005), p 42 All figures are 2004 dollars.

[21] Similar savings were found using EPA and environmental NGO estimates. See Ibid., pp. 9 and 42.

[22] Yang, J. and Benkovic, S., "The Feasibility of Using Cap and Trade to Achieve Sulfur Dioxide Reductions in China," *The Sinosphere Journal,* 4:1, 10-14, July, 2002

[23] Fernando, P. et al, *Emissions Trading in the Energy Sector: Opportunities for the People's Republic of China,* Asian Development Bank, Manila, 1999; and Morganstern, R. et al, "Demonstrating Emissions Trading in Taiyuan, China," *Resources,* Issue 148, 7-11, Summer, 2002.

[24] See http://www.chinadaily.com.cn/bizchina/2006-08/02/content_655234.htm

中美工程技术研讨会论文集

SINO-AMERICAN TECHNOLOGY AND ENGINEERING CONFERENCE

环保组

Environmental Protection

中国·北京

2006年10月