ENVIRONMENTAL ENERGY INSIGHTS

A STRATEGIC INFORMATION SERVICE

Volume VII, Issue 2
March/April 2004

INSIGHTS

A Resurgence in New Coal-Fired Power Plants

Summary: While coal has historically served as the fuel source of choice for generating electricity in the U.S., economic and environmental considerations caused electric generating companies to turn almost exclusively to natural gas in the 1990s as the fuel for new generating capacity. Recently, however, this trend has changed, and companies are again looking at coal to satisfy at least a portion of their future capacity needs. Contributing factors include the volatility of natural gas prices, deregulation of the electric utility industry and an administration that looks kindly on the use of coal for electricity generation.

Ninety-four new coal plants have been announced, representing 62 GW of capacity. Most of these projects are only in the initial phases of development, and many undoubtedly will not be built. The amount of new capacity that will actually be constructed will depend on a range of site-specific and market factors. Notwithstanding major research and development efforts aimed at developing new pollution control and coal-based generation technologies, environmental stakeholders will likely continue to oppose new coal-fired generation.

History of Coal-Fired Electric Generation in the U.S.

Coal has historically been the fuel of choice worldwide for generating electricity, since it is the most abundant and widely dispersed energy source, with reserves enough to last two to three centuries. While the U.S. has only three to four percent of the global supply of natural gas, it holds about one-quarter of the world's coal supply. This has contributed to coal's price stability and to its dominant position in the U.S. electric generating mix. The contribution of coal to the country's generation mix has been relatively stable over the last half century, varying from between 44 and 57 percent of total generation between 1950 and 2002. In the late 1960s and early 1970s, heavy dependence on relatively cheap petroleum for generating electricity and the construction of large base-load nuclear plants supplanted a significant amount of coal-fired generation. However, coal regained market share in the years following the 1973 oil embargo, due to concerns over the availability of petroleum imports and increasing petroleum costs. Federal

Continued on page 2 ➲

This month in Insights:

M. J. BRADLEY & ASSOCIATES

Environmental Energy Insights

Environmental Energy Insights is published monthly by M. J. Bradley & Associates. *Insights* provides analysis of important regulatory and policy developments in the environmental and energy areas.

Editor: Ann G. Berwick, Esq.

If you have a suggestion for a topic you would like to see featured in *Insights* or would like to comment on a previous article, contact us at the address below or send e-mail to insights@mjbradley.com.

To request documents referenced in *Insights* send e-mail to insights@mjbradley.com or try the Clean Energy Group website at http://www.mjbradley.com

M. J. Bradley & Associates
47 Junction Square Drive
Concord, MA 01742

Telephone: (978) 369-5533
Fax: (978) 369-7712
Internet:
http://www.mjbradley.com

Printed on recycled paper

Continued from page 1

legislation passed in 1978 imposed restrictions on the use of both petroleum and natural gas for generating electricity, thereby encouraging further coal use.

The tide turned to some degree during the 1990s with the passage of the 1990 Clean Air Act Amendments, which established a number of new requirements for substantial reductions in pollution emissions from coal-fired power plants. The promulgation of new National Ambient Air Quality Standards for $PM_{2.5}$ and ozone in 1997 set the stage for additional reductions of SO_2 and NOx emissions from coal-fired power plants. In addition, a number of states began to address power plant emissions, with coal plants the prime target.

As a result, coal's share of total electric generating capacity decreased from its peak of about 57 percent in the mid to late 1980s, to 51 percent in 1995 and 50 percent in 2002. With amendments to federal law in 1987 easing restrictions on the use of natural gas, almost all of the market share that coal lost over this period has been captured by natural gas. Utilities turned to gas in the 1990s because the plants were cheaper to build and cleaner to operate than coal plants. Until only very recently, very few, if any, new coal plants had been proposed in the U.S.

Factors Contributing to Coal's Rising Popularity

Coal has gained momentum with the rise of natural gas prices and reductions in estimates of oil and natural gas reserves. New finds of natural gas have tailed off and existing fields are becoming depleted more rapidly than expected. As a result, short-term gas prices have spiked sharply and long-term gas price projections have increased. The Energy Information Administration's (EIA's) most recent forecast (AEO 2004) predicts gas prices rising from $3.77/mmBtu in 2002 to $4.92 in 2025. Other forecasters project even higher prices. According to McIlvaine, an environmental energy market research company, coal becomes a more attractive alternative for new electric generating capacity when the price of natural gas exceeds about $3/ mmBtu.

The Bush administration's coal-friendly policies are another driver for coal's resurgence. According to the administration, continued use of coal is integral to its energy strategy of maintaining fuel diversity. New "clean coal" technology R&D programs (see discussion below) support this strategy, as do new regulatory policies such as the reform of New Source Review and the proposed mercury trading program.

Deregulation of the electric utility industry in some states is a third driver. Prior to deregulation, utilities that owned coal plants were reimbursed only for their "prudently incurred" costs, and were allowed to earn a limited profit on their investment capital. Huge cost overruns on new power plant construction in the 1980s, particularly on large base-load coal and nuclear plants, caused regulated utilities to become more risk-averse towards building new plants of this nature. The limited return they could make on these large investments was no longer viewed as worth the risk. Deregulation has changed that picture by allowing plant owners to sell electricity to wholesale purchasers, often at prices set with reference to plants on the margin. These are typically the higher-cost gas plants. This has changed the risk/reward environment significantly, making coal plant investments more appealing.

A final driver for the development of new coal plants is the age of the existing fleet. Eighty percent of the country's coal-based capacity will be at least 30 years old by 2007. Thus, the vast majority of existing coal plants are either at or close to the age at which operating and maintenance costs will make them uncompetitive in the wholesale generation market or at which they will require major capital improvements in order to remain

Continued on page 3 ➲

Continued from page 2

competitive. These capital improvements may trigger requirements to install new air pollution controls. Large expenditures on these plants may or may not be economic, depending on how many additional years of life can be expected, the projected return on the investments, and the cost of such alternatives as building a new coal or gas plant.

Projections for New Coal Generation

As indicated above, most of the recent additions in electric generating capacity have been natural gas-fired. Of the 187 GW of new capacity added between 2000 and 2003, 175 GW is gas-fired. Only about five GW of renewables, mostly wind, and less than one GW of coal, were added over the same period.

Recent capacity additions have outpaced demand substantially, and therefore the near-term need for new capacity is low. But more capacity will be needed as demand increases and older plants are retired. EIA predicts that from 2002 to 2025, 356 GW of new electric generating capacity will be needed, mostly after 2010. Between 2002 and 2010, only 88 GW of new capacity (57 GW of which are already in development) is projected to be required. However, between 2011 and 2025, the amount of new capacity is projected to grow to 268 GW, an average of 19 GW annually.

Of the new capacity, about 62 percent is projected to be natural gas-fired combined-cycle combustion turbines or distributed generation technology. Coal, primarily advanced pulverized coal, is projected to account for nearly one-third of all new capacity over the forecast period. From 2011 to 2026, 105 GW of new coal-fired capacity is expected to be brought on-line, more than half of it after 2020, when natural gas prices are expected to rise significantly. From 2011 on, coal-fired capacity is expected to account for 40 percent of all capacity additions.

Based on these projections, coal is expected to remain the primary source of electricity through 2025. In 2002, coal accounted for 50 percent of total generation, including the output from combined heat and power plants. Coal generation is projected to maintain a 50 percent share through 2010 and grow to 52 percent in 2025.

Clean Coal Technology

Most of today's coal-fired power plants are based on 50- to 100-year-old technology that was not developed to be ultra-clean or to minimize CO_2 emissions. Rather than designing new integrated system designs in the face of environmental regulations, companies have retrofitted old technologies with add-on equipment.

In the late 1980s and early 1990s, DOE conducted a program with industry and the states to demonstrate a new generation of coal-based energy processes that sharply reduce pollution compared to older technology. Ultimately, 35 pioneering plants were launched as part of the DOE's Clean Coal Technology program, with more than 20 of the technologies tested achieving commercial success. Among the success stories were advanced electric power generation technologies such as Fluidized-Bed Combustion and Integrated Gasification Combined Cycle, and air pollution control technologies such as low-NOx combustion systems and selective catalytic reduction. The federal government's share of the Clean Coal Technology program totaled $1.4 billion; industry contributed another $2.3 billion.

The Bush administration has committed to the development of even more advanced clean coal technologies. DOE's Clean Coal Power Initiative (CCPI) is a renewed industry/government partnership that targets $2 billion for a ten-year research and development (R&D) program. In 2003, eight projects totaling $1.3 billion were announced under the CCPI, with over $1 billion to come from the private sector.

The CCPI aims to develop technologies that will allow for the use of existing coal plants for the next ten to 20 years with improved emission

Continued on page 4 ➲

Clean Coal Technology—New Plant Performance Targets[1]

	Reference Plant[2]	2010	2020
SO_2	98% removal	99% removal	>99% removal
NOx	0.15 lb/mmBtu	0.05 lb/mmBtu	<0.01 lb/mmBtu
PM	0.01 lb/mmBtu	0.005 lb/mmBtu	0.002 lb/mmBtu
Mercury	Co-benefits[3]	90% removal	95% removal
By-product Utilization	30%	50%	Near 100%
Plant Efficiency	40%	45-50%	50-60%
Availability	>80%	>85%	>90%
Plant Capital Cost ($/kW)	1000-1300	900-1000	800-900
Cost of Electricity (¢/kWh)	3.5	3.0-3.2	<3.0

[1]Plant efficiency, availability and cost targets are for plants without carbon capture and sequestration, that use current cooling tower technology.
[2]Plant that can be built using current state-of-the-art technology meeting New Source Performance Standards.
[3]Some mercury reductions will be achieved as a co-benefit of existing environmental control technologies

Continued from page 3

Clean Coal Technology—Existing Plant Targets

	2005	2010
NOx Emissions	Reduce cost for achieving <0.15 lb/ mmBtu to ¾ that of SCR	Reduce cost for achieving <0.10 lb/mmBtu to ¾ that of SCR
PM Emissions	n/a	99.99 % capture of 0.1-10 micron particles
Hg Emissions	Achieve 50-70% reduction at less than ¾ cost of activated carbon	n/a

controls, as well as to develop very low-emitting technologies for new plants. DOE has set environmental and economic performance targets for new plants for 2010 and 2020, and for existing plants for 2005 and 2010.

Barriers to New Coal Generation

New coal plants face numerous regulatory hurdles as they move through the development process. Local, state and federal officials all have some measure of responsibility for approving new coal plants, although the lion's share of authority rests with the states. Assuming that a new coal-fired electric power plant can be licensed at all, licensing, design and construction may take four to six years, due at least in part to environmental considerations. Retrofitting existing plants with emission control equipment may take two to three years.

Environmental groups generally oppose even new coal plants equipped with state-of-the-art pollution controls, and prefer to see a gas-fired or renewable energy plant built, or no plant at all (advocating for demand side management in lieu of supply-side sources). A particular concern is CO_2 emissions, which cannot be cost-effectively removed from conventional coal-fired power plants. The prospect of future CO_2 regulation is an important factor militating against the construction of conventional coal plants.

Transmission constraints represent another potential road-block for any new electric generating facility, coal-fired or otherwise. In many parts of the country, institutional regulatory arrangements for transmission systems are in serious disarray. The primary sticking point is that the first power plant developer that needs to tie into a transmission line that has capacity constraints has to pay to upgrade the line, but subsequent developers do not.

A number of states, including Illinois, Montana and New Mexico, have required the consideration of alternative technologies such as IGCC as part of the best available control technology (BACT) analysis for new plants. EPA has established a working group to examine the issue of whether alternative technologies must be considered in that context. A policy document is being drafted that would reportedly clarify EPA's view that BACT reviews for conventional coal-fired power plants are limited to the evaluation of best available pollution controls.

New Coal Plants in Advanced Stages of Development

According to recent DOE National Energy Technology Laboratory data, 94 new coal plants had been announced as of February 2004, with approximately 62 GW of capacity. This represents about seven percent of total net U.S. generating capacity from all fuel sources. Illinois leads the way with ten coal plants announced, followed by Kentucky with eight and Montana with six. The coal capacity that will actually be built will depend on site-specific and market factors, such as natural gas price/ availability, demand, the ability and cost of resolving siting and environmental permitting issues, access to transmission, and cost of capital. Thus, it is likely that many of the announced plants will not be built. Nonetheless, the relatively large number of facilities under consideration, compared to the situation just a few years ago, signals a definite change in market dynamics.

Of the new coal plants that have been announced, relatively few are far along in development. Some of the proposed projects are meeting stiff resistance due primarily, although not exclusively, to environmental concerns. A discussion of some of the more controversial proposals follows.

Bull Mountain Power Roundup Project

Although permits have been issued for its proposed coal-fired facility, Bull Mountain Power's 700 MW Roundup project in Montana has faced intense opposition over possible visibility impairment in Yellowstone Park and other environmental impacts. Bull Mountain Power plans to install dry scrubbers, SCR and baghouses to control emissions from the plant. Environmental groups have filed suits in an attempt to force the Department of the Interior and the Montana Department of Environmental Quality either to block the project or to require more stringent air pollution controls or additional offsets. While the courts have thus far ruled in favor of the project developer, appeals are currently pending. Despite the ongoing legal battles, Bull Mountain plans on beginning construction by the end of this year.

Peabody Energy Thoroughbred Plant

Peabody Energy's proposed 1,500 MW Thoroughbred coal plant in Muhlenberg County, Kentucky encountered a setback recently when negotiations over its air permit broke down. With the assistance of a mediator, Peabody had been negotiating the terms of the permit with the Sierra Club and other environmental groups that had appealed the decision by Kentucky regulators to grant Peabody's air permit. The project is being challenged over visibility concerns in Mammoth Cave National Park. The

Continued on page 5 ➲

Continued from page 4

parties expect the matter to go before a state hearing officer in late July.

GenPower LLC Longview Power Plant

The West Virginia Department of Environmental Protection has granted GenPower LLC an air quality permit authorizing construction of a 600 MW coal plant near Morgantown. The plant will be equipped with low-NOx burners and SCR for NOx control, a wet scrubber for SO_2 control, and a baghouse to control PM. In addition, GenPower has agreed to purchase and retire SO_2 allowances equivalent to 110 percent of its compliance requirement.

However, the National Park Service (NPS), the U.S. Fish and Wildlife Service (FWS), EPA and citizens are opposing the state's permit decision. The NPS and FWS are concerned that the plant would increase acid rain and visibility degradation in the Doly Sods and Otter Creek Wilderness areas and in Shenandoah National Park. EPA wants more effective air pollution control equipment to be required. The Sierra Club, Trout Unlimited and the National Parks and Conservation Association have appealed the permit. The earliest that construction could begin is late this year or early next year.

We Energies Oak Creek Power Plant Expansion

We Energies has proposed building two new 615 MW supercritical pulverized coal units and one 600 MW IGCC unit at its existing Oak Creek Power Plant. In November 2003, the Wisconsin Public Service Commission issued a decision approving the installation of the two pulverized coal units but ruled that the IGCC facility is not economic. In January 2004, the Wisconsin Department of Natural Resources issued a construction permit for the proposed pulverized coal units. Clean Wisconsin, a local grassroots public interest group, and other stakeholders have filed lawsuits opposing various aspects of the state's permitting for the project.

Great Northern Power Miles City Power Plant

Great Northern Power is planning to build two 500 MW plants in Montana and North Dakota that would generate power from a mix of wind and coal using fluidized-bed technology. However, the company has not yet identified a suitable connection to an existing transmission network that will allow it to sell power to other states in which there is a greater demand for cleaner power. This could doom the project.

Reliant Energy Seward Waste Coal Power Plant

Reliant Energy is constructing what will be the world's largest waste-coal power plant at a site in Westmoreland County, PA. The $800 million, 521 MW fluidized-bed plant will replace an 82-year-old coal plant at the same location. Construction of the plant is virtually complete and start-up testing is scheduled to begin later this spring. Local business interests have welcomed the project. Opinions on the environmental impacts have been mixed. Some view the new technologies and reduced emissions as positive from an environmental standpoint. Others would rather see a renewable energy facility installed.

Conclusion

While soaring gas prices, a coal-friendly administration and other factors have definitely changed the views of electric generating companies on building new coal-fired power plants, it remains to be seen just how many of the 94 announced new coal projects will actually get built over the next 20 years. Factors that we have touched on here that are likely to influence the amount of new coal capacity installed over this period include the price of natural gas, the future of industry deregulation, the stringency of new air pollution emission limitations governing coal plants (including limits for CO_2), and the progress of new clean coal and air pollution technologies.

That said, we have not exhausted the topic. The development of renewable energy technologies, national attitudes towards nuclear power and increasing the imports of liquefied natural gas—not to mention the next several presidential elections—will also have enormous impacts on the future of coal generation.

Insights:

Coal accounts for about 50 percent of the total electric generating mix in the U.S., and all of the other generation options face challenges of their own. Thus, coal will continue to play an important role in producing electricity in the foreseeable future, regardless of the direction of any new energy policy. For this and other reasons, the search for ways of making coal-fired power plants cleaner and more efficient is intense.

Improved pollution control technologies are necessary to provide a transition between today's fleet of coal-fired electric generating facilities and future coal plants that are substantially more efficient, emit much less pollution, and are able cost-effectively to capture CO_2.

A mandatory CO_2 reduction requirement would certainly have an impact on proposals for new coal plants, and could well be a driver for a new generation of coal technology.

It remains to be seen exactly how much new coal plant development will occur, considering the local resistance many new plants will face. That said, new coal plants will likely be more welcome in states whose economy relies significantly on coal-mining.

RGGI and the Concern about "Leakage"

Summary: Policymakers in the Northeast, under the auspices of the Regional Greenhouse Gas Initiative (RGGI), have begun to develop a program to limit CO_2 emissions from power plants. Establishing a policy that will increase the costs of producing electricity within the region raises concerns because of the interconnections linking power markets in the eastern U.S. As electricity bid prices increase in the RGGI states to reflect the costs of compliance with a regional CO_2 mandate, energy production will tend to shift to lower cost power producers outside of the region, which in turn may increase emissions. This "leakage," as it's called, runs the risk of reducing the effectiveness of the program. Computer simulations performed as part of the Connecticut Climate Change Stakeholder Process and by the New York Greenhouse Gas Task Force suggest that a regional CO_2 cap could result in significant leakage, seriously undermining the goals of the policy. This article discusses possible strategies for addressing this concern, none of which appears to be a perfect solution. The RGGI stakeholders have their work cut out for them, both to evaluate the proposals that are on the table and, possibly, to identify other mechanisms to limit leakage.

Under the auspices of the Regional Greenhouse Gas Initiative (RGGI), policymakers in nine northeastern and mid-Atlantic states have begun to consider possible strategies for regulating CO_2 emissions from the electric generating sector. The nine states are Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont. Representatives of Maryland, the District of Columbia, Pennsylvania, the Eastern Canadian Provinces Secretariat and New Brunswick are observers in the process. The RGGI efforts are currently focused on the development of a cap-and-trade program similar to the NOx trading system in the eastern U.S. and the national SO_2 trading program for acid rain.

However, industry and environmental stakeholders alike have raised concerns regarding the potential for "leakage" from a traditional cap-and-trade approach. This article describes the leakage problem, and discusses the strategies that are being proposed in an effort to minimize leakage in the RGGI context.

Leakage Defined

As electricity bid prices increase in the Northeast to reflect the costs of compliance with a regional CO_2 mandate, energy production will tend to shift to lower cost power producers that are outside of the regulated area but joined to it by the electricity grid, which may increase emissions. The increase in emissions that results from this shift in power production is known as leakage. Leakage can also occur within the capped region. For example, utilization of on-site power facilities not subject to the CO_2 limits by virtue of their small size may increase, offsetting reductions in energy production and emissions by facilities subject to the cap. Both scenarios represent a form of leakage, although increased emissions from sources outside of the Northeast are the greater concern.

This shift in power production to unregulated sources has two important consequences. First, it is likely to reduce the effectiveness of the program by increasing emissions overall. If competing power facilities in neighboring power markets were zero-emitting, then no leakage would occur despite the shift in production. However, states to the west and south of the RGGI region, where the bulk of the energy trade occurs, have substantially higher average CO_2 emission rates. (See the chart on the following page.) As a result, emissions are likely to increase as power production shifts to these areas. Second, shifts in power production will hurt the competitiveness of CO_2-regulated companies, which will be impacted by the increase in demand for electricity from outside the capped region.

During peak periods of electricity demand, transmission constraints limit power imports, which would constrain leakage. However, if a significant price differential resulted from CO_2 limits in the Northeast, there would likely be increased interest in addressing current transmission constraints.

Proposed Solutions to the Leakage Problem

Concerns about leakage have arisen in the context of RGGI's focus on the traditional cap-and-trade approach, in which a cap is set, and then allowances are allocated to *electric generating companies*. In an effort to minimize leakage, two alternatives are under consideration, one focusing on the supply side; the other, on the demand side.

- The *supply side approach* more closely resembles a traditional cap-and-trade regime, in the sense that it is the electric generating companies that would be subject to regulation. However, allowances would be allocated on an output-basis, rather than on the more familiar heat-input basis.
- The *demand side system* is a more fundamental departure from the usual approach to cap-and-trade, in that the electricity suppliers would be regulated, rather than the generators. Electricity suppliers, or Load Serving Entities (LSEs), purchase electricity from generating companies and supply power to end use customers. The system would utilize an emission

Continued on page 7 ➲

Power Markets in the Northeast

There are three interconnected wholesale power markets in the Northeast: (1) the PJM Interconnection, which serves the largest peak load; (2) the New York Independent System Operator (NYISO), which is the next largest; and (3) ISO New England. PJM serves all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia; the NYISO serves the state of New York; and ISO New England serves the six New England states.

The power markets in the Northeast are physically interconnected, with energy imported and exported on a continuous basis. PJM has interconnection ties with systems in the Midwest, Southeast, and New York. NYISO is interconnected with PJM, ISO New England, the Independent Electricity Operator of Ontario, and Hydro-Quebec. ISO New England is interconnected with New York, Hydro-Quebec and New Brunswick. All of this is what allows market participants to take advantage of price differentials, and results in the potential for leakage from the carbon-regulated region.

Continued from page 6

portfolio standard (EPS), which could be either rate-based or allowance-based.

The Supply Side Approach: Output-Based Allocations

On the supply side, certain stakeholders have proposed a cap-and-trade program for *electric generating facilities*, but with a variation on the usual cap-and-trade approach: namely, that allowances would be allocated on an updating output basis in order to mitigate leakage. Under existing cap-and-trade regimes, electric generating facilities have been the regulated entities, but allowances have been allocated on an historical fixed heat-input basis. With the proposed approach, a facility's allocation would periodically be recalculated based on its share of historical electric generation output (i.e., megawatt hours).

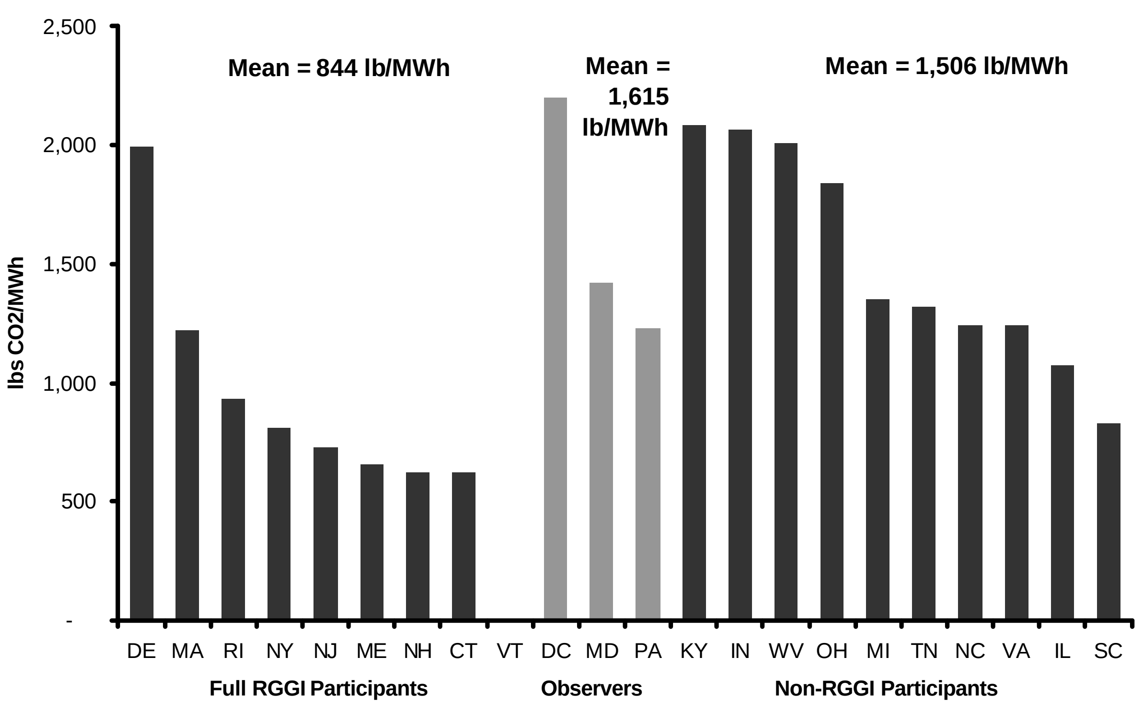
Advocates of output-based allocations have traditionally emphasized that this approach rewards cleaner sources of generation relative to a fixed input-based allocation. However, with the design of a regional climate initiative in play, some stakeholders argue that an output-based allocation methodology will have the added advantage of mitigating leakage.

The output subsidy effect

Recall what leakage is: the shift to lower cost, higher emitting power producers that are outside of the CO_2-regulated area but joined to it by the electricity grid. The lower cost of production outside of the regulated area is what causes leakage. *Some economists argue that an output-based allocation methodology will tend to reduce electricity prices relative to other forms of allocation.*

Continued on page 8 ➲

CO_2 Emission Rates inside and outside of the RGGI Region



Continued from page 7

Because electricity prices within the regulated area are theorized to fall in response to output-based allocations, again relative to alternative forms of allocation, the electricity price differential between the regulated and unregulated areas will also be reduced. This so-called "output subsidy effect" should reduce the demand for power from the unregulated area, in theory thereby reducing leakage.

The output subsidy effect is based on the theory that companies will reduce their electricity bid prices by factoring in the future value of the allowances they will earn. The system operators (e.g., PJM) will respond by calling on facilities that have lowered their bid prices to serve a greater share of the load. A facility that increases its share of output increases the number of allowances it receives. By reducing its bid price, a facility will gain both the value of the additional allowances it gets and the additional revenue from the increased power sales (minus the operating costs attributable to the increased utilization of the facility).

Here is another way to think about what we have just said:

- With a conventional fixed input-based allocation methodology, a generating company's bid price will equal its marginal operating costs, including fuel and variable operation and maintenance (VO&M), as well as the cost of allowances:

  Bid Price = Fuel + VO&M + Allowance Cost

- With an output-based allocation, there will also be a negative cost adder reflecting the value of the allowances earned (VAE):

Bid Price = Fuel + VO&M + (Allowance Cost - VAE)

Is the output subsidy effect real?

Modeling of air and climate policy scenarios show the output subsidy effect because modelers program it to occur. (The output subsidy effect is assumed in modeling performed by Resources for the Future, EPA and ICF Consulting.) But the question remains as to the degree to which it would actually occur in the real world. In fact, a number of factors, which we discuss next, would likely moderate the extent to which companies would reduce their bid prices in response to an output-based allocation scheme.

The allowances earned from increasing output would not be received for some time, perhaps years, after the company's decision to reduce its bid price. Thus, companies would apply a discount factor to the projected future value of the allowances earned (i.e., thereby reducing the VAE). Uncertainties about intervening changes to the policy and the continuation of the allowance market might cause a company to jack up its discount factor substantially. Also, the variable costs of operating a facility (e.g., fuel costs) would be incurred in the present while the allowances would not be distributed until well in the future. This cash management issue could also discourage a company from significantly reducing its bid price.

Also, to earn additional allowances, a company would have to increase its output relative to all other sources within the regulated domain. But increasing output in one market (e.g., New England) does not guarantee that a company will increase its output relative to all other sources within the regulated region. For example, a unit in the New England market could reduce its bid price and increase its output, only to have sources in the PJM market increase their output by an equivalent amount. Without increasing its *relative* share of the output across the entire regulated area, the unit will have reduced its bid price without having earned any additional allowances. This risk might discourage a company from reducing its bid price.

Finally, the price paid to generators for electricity (known as the clearing price) is based on the last unit dispatched. If the clearing price is reduced because the last unit dispatched reduces its bid price, then all units within the market (e.g., PJM), regardless of whether they engage in this pricing behavior, will face a reduction in revenues. If the reduction in a unit's bid price actually lowers the clearing price of electricity, the revenue earned by the company's entire fleet will be reduced. It remains to be seen whether companies will wager that the eventual redistribution of allowances will increase their long-term profitability sufficiently to justify this behavior.

The Demand Side: Environmental Performance Standards

Unlike the approach we have just discussed, which would regulate electricity generators, an EPS would regulate retail electricity suppliers. An EPS could be either rate-based or allowance-based. By regulating CO_2 at the point of supply, policy makers would create a direct incentive for implementing cost-effective controls options (e.g., contracting for low-carbon energy supplies or implementing energy efficiency projects). Additionally, an EPS imposes a uniform standard on LSEs regardless of the geographic origin of the power they sell to end users, which addresses the problem of leakage.

A rate-based EPS

A rate-based EPS would require retail electricity suppliers to meet an output-based performance standard (expressed in lbs/MWh) based on the electricity that they supply to their customers. Unlike a traditional cap-and-trade program, a rate-based EPS would avoid the need for an

Continued on page 9 ➲

Continued from page 8

allowance allocation.

Development of a rate-based EPS would require, first, identification of an aggregate, tonnage emission reduction goal for all of the affected sources in the region and, second, projection of the aggregate electricity demand during the target time period. The standard would be derived by dividing the tonnage goal by the projected electricity demand, and would be updated periodically to ensure that emissions were being reduced.

Depending on its design, an EPS could provide suppliers with at least the following three compliance options:

- Securing electricity supply contracts with the appropriate emissions profile. This would involve the purchase of a balanced portfolio of higher and lower carbon-intensive resources, and would create a direct incentive for retailers to pursue contracts with low- and zero-emitting facilities.
- Trading carbon certificates. Retail suppliers whose actual portfolio emission rate exceeded the EPS could purchase tradable certificates from retail suppliers whose rate was lower than the standard.
- Trading carbon offsets. LSEs could purchase project-based emission reductions, known as carbon offsets, from sources outside the cap.

An allowance-based EPS

There is another possibility for designing an EPS, which would keep the compliance requirement on the retail supplier rather than on the generator, but would impose a cap on CO_2 emissions instead of setting a performance standard. The supplier would then surrender CO_2 allowances for the emissions associated with the power delivered to end users. LSEs would have the same compliance options described above in the context of a rate-based EPS.

The advantage of an allowance-based approach, as compared to a rate-based EPS, is the certainty associated with establishing a fixed cap on emissions. (Recall that to maintain emissions at the level of the cap, a rate-based approach would require periodic recalculation in order to square actual and projected demand.) The disadvantage of the allowance-based approached is as its name suggests: allowances must be allocated, which is a highly contentious enterprise.

Note that the electricity tracking infrastructure currently operating in some areas of the Northeast and under development in others could be leveraged to implement an EPS in the region. Currently, retail suppliers must comply with renewable portfolio standards in certain states, using tradable renewable energy certificates. The same information currently tracked for compliance with renewable portfolio standards and for associated environmental disclosure requirements could be used in implementing an EPS program.

State EPS efforts to-date

Legislatures in Connecticut, Massachusetts, and New Jersey have called for the development of an EPS, although no state has adopted a final policy. Additionally, the Northeast States for Coordinated Air Use Management (NESCAUM) has developed a model EPS rule.

The Connecticut electric restructuring law authorizes the DEP to establish uniform performance standards for electric suppliers serving customers in Connecticut, for NOx, SOx, CO_2, CO and mercury. However, the DEP can establish a standard only if three of the states participating in the Ozone Transport Commission, with a total population of at least 27 million, adopt similar standards. This means that New York would have to be one of the states. Connecticut has issued a draft rule, which has an EPS of 1,100 pounds of CO_2 per megawatt hour (lb/MWh).

The Massachusetts electric restructuring law authorizes the DEP, together with the Attorney General and Department of Telecommunications and Energy, to adopt an EPS for any pollutant determined by the DEP to be of concern to public health. The legislation requires the DEP to develop standards for at least one pollutant on, but not before, May 1, 2003. It has not yet done so.

The New Jersey restructuring law authorizes the Board of Public Utilities to implement an EPS for all retail electric suppliers if two or more states in the PJM control area representing at least 40 percent of electricity usage adopt an EPS. The standard would require retail suppliers serving customers in New Jersey to meet specific standards for NOx, SO_2 and CO_2.

The NESCAUM model rule sets output-based emission standards for five pollutants (NOx, SO_2, CO_2, mercury and CO). The standards were designed to reflect the average emission rates in the ISO New England market, not to achieve specific emission reduction goals. The rule is available at http://www.nescaum.org/workgroups/energy.html.

Possible disadvantages of an EPS approach

Critics of the EPS approach raise a number of issues. First, there would be no emissions cap on electric generating sources that would require actual on-site reductions; rather, the market would be left to respond to the EPS constraint. Many regulators and environmental stakeholders find this state of affairs unsettling.

Second, quantification of the emissions associated with

Continued on page 10 ➲

Continued from page 9

imported power introduces uncertainties by relying on pool average emission factors. Power purchases fall into three general categories: generator-specific contracts, utility-specific contracts and spot market purchases. The emission profile of the power for the various arrangements is not always known. As a result, power pool average emission factors are utilized, which will over- or under-estimate emissions from a given facility.

Finally, there are questions as to whether an EPS will fully address the leakage issue. It is conceivable that an EPS requirement could be manipulated, with generating companies outside the region contracting only their lowest carbon resources into the region and generating companies within the region contracting their highest carbon resources outside the region. In this scenario, energy contracting arrangements would simply be reshuffled, rather than actually reducing emissions.

Insights:

There has yet to emerge a definitive strategy to the problem of leakage. The cleanest solution would be to adopt a national climate policy. However, given the low probability of this occurring in the short-term, policymakers will have to be creative with the tools available to them to create a program that both achieves its environmental goals and protects the competitiveness of the companies in the region.

There are advantages to regulating a pollutant close to the end user (e.g., by imposing an EPS on retail suppliers). This upstream approach creates a direct incentive for implementing cost-effective control options. The challenge will be to increase confidence in the systems for tracking compliance, and to devise an appropriate system for quantifying and tracking the emissions associated with imported and exported power.

Many stakeholders view an output-based approach to allocation as desirable because it encourages the development of new, more efficient power plants. This is a substantial benefit in and of itself, particularly in the context of a climate policy. Less clear is whether an output-based allocation would mitigate leakage by depressing electricity bid prices. A host of factors (e.g., price risk, regulatory risk, market risk) suggest that the impact could be much smaller than the theory suggests.

The Future of Nuclear Power: An Interdisciplinary MIT Study

Summary: Last summer, the Massachusetts Institute of Technology released *The Future of Nuclear Power: An Interdisciplinary MIT Study,* which it billed as "the most comprehensive, interdisciplinary study ever conducted on the future of nuclear energy." The report recommends that the nuclear option be retained because of its importance in addressing climate change. But while concluding that nuclear power should remain on the table as a viable alternative, the authors cite four major problems that they view as unresolved: high relative costs, adverse safety and environmental issues, security risks related to proliferation, and long-term management of nuclear wastes. Addressing the related issues of proliferation and waste management, the report weighs in heavily in favor of the open, once-through fuel cycle as opposed to the closed fuel cycle; the latter involves the reprocessing of spent nuclear fuel.

A report released in July 2003, entitled *The Future of Nuclear Power: An Interdisciplinary MIT Study,* examines both the advantages of nuclear power and the challenges it faces. The report has received substantial attention, presumably due both to the depth of its analysis and the luminaries associated with it. They include Harvard Professor John Holdren, former Indiana Congressman Phil Sharp, E. Linn Draper of AEP, Clinton White House Chief of Staff John Podesta, Thomas Cochran of the Natural Resources Defense Council, and several prominent Massachusetts Institute of Technology professors.

The study starts on a pessimistic note: "Nuclear power faces stagnation and decline." However, it concludes that because energy production and use will make a huge contribution to global warming, nuclear power should be one of several options for reducing carbon dioxide emissions. (The other options that it mentions, but does not discuss, are expanded use of renewable energy sources, carbon sequestration, and increased energy efficiency.) The study focuses on what it would take for nuclear power to remain on the table as a viable strategy for addressing climate change and the growing need for electricity.

The analysis uses a global growth scenario that would expand current worldwide nuclear generating capacity almost threefold, resulting in 1,000 to 1,500 reactors of 1,000 megawatt-electric (MWe) capacity each (compared to a current capacity equivalent to 366 such reactors).

Continued on page 11 ➲

Continued from page 10

According to the report, this would avoid about 25 percent of the increment in carbon emissions otherwise expected given business as usual. The report adopts this stunningly aggressive scenario based on the view that the effort to overcome the associated challenges is justified only if nuclear power can have a significant impact on global warming.

The report concludes that in order for the use of nuclear power to increase significantly, four critical problems must be solved. They are:

- cost;
- safety;
- waste; and
- proliferation.

The Context

In 2002, nuclear power supplied 17 percent of the world's electricity consumption. Worldwide consumption is projected to increase dramatically in the coming decades, especially in the developing world, with nuclear electricity generating capacity globally projected to grow by only five percent by 2020.

In the U.S., nuclear power supplied 20 percent of electricity consumption in 2002, with 103 licensed reactors at 65 plant sites. According to the Congressional Research Service, no nuclear plants have been ordered since 1978 and more than 100 reactors have been canceled, including all ordered after 1973. However, as of approximately six months ago, 16 commercial reactors had received 20-year license extensions, license extensions for 14 more reactors were under review, and more were expected.

Cost

According to the report, nuclear power will succeed in the long run only if it costs less than competing technologies. It currently does not. The authors construct a model to compare the costs of electricity from nuclear power, coal and gas. They assume an 85 percent capacity factor and a 40-year life for the nuclear plant, a number of projected improvements in nuclear cost factors, and a range of gas prices. The comparative power costs appear in Table 1.

Table 1

Comparative Power Costs

CASE (Year 2002 $)	REAL LEVELIZED COST Cents/kWe-hr
Nuclear (LWR)	6.7
+ Reduce construction cost 25%	5.5
+ Reduce construction time 5 to 4 years	5.3
+ Further reduce O&M to 13 mills/kWe-hr	5.1
+ Reduce cost of capital to gas/coal	4.2
Pulverized Coal	4.2
CCGT[a] (low gas prices, $3.77/MCF)	3.8
CCGT (moderate gas prices, $4.42/MCF)	4.1
CCGT (high gas prices, $6.72/MCF)	5.6

a. Gas costs reflect real, levelized acquisition cost per thousand cubic feet (MCF) over the economic life of the project.

Table 1 indicates that in the base case (which is discussed in detail in the report) nuclear power is much more costly than the coal and gas alternatives. The report cites its "bottom line" conclusions that

> with *current expectations* about nuclear power plant construction costs, operating cost and regulatory uncertainties, it is *extremely unlikely that nuclear power will be the technology of choice for merchant plant investors* in regions where suppliers have access to natural gas or coal resources (emphasis added).

The authors add that this conclusion might not hold where plants are state-owned or heavily subsidized.

However, if certain cost improvements were made—and the authors emphasize that these improvements are significant (e.g., a 25 percent reduction in construction costs, an investment environment in which nuclear plants can be financed under the same terms as coal plants)—new nuclear power plants could become competitive with natural gas and coal. The authors judge the identified cost improvements to be "plausible," but "not proven."

Additionally, if the social costs of carbon emissions were internalized through a tax or cap-and-trade system, the competitiveness of nuclear power would improve. For example, with carbon taxes in the $50/ton range, nuclear is not economical in the base case, but becomes competitive if all of the cost reductions identified are realized. See Table 2. (Note that the assumption here is that the cost of carbon would be reflected in the price of electricity, but that other externalities like the costs associated with nuclear waste and the air pollution from the use of fossil fuels would not.)

Recommendations

The following are among the actions the report suggests to improve the economic viability of nuclear power:

- support for a number of Department of Energy initiatives, including government cost sharing for site banking for a number of plants, and combined construction and operating licenses for new plants;
- the inclusion of nuclear power in any mandatory

Table 2

Power Costs with Carbon Taxes

CARBON TAX CASES LEVELIZED ELECTRICITY COST cents/kWe-hr	$50/tonne C	$100/tonne C	$200/tonne C
Coal	5.4	6.6	9.0
Gas (low)	4.3	4.8	5.9
Gas (moderate)	4.7	5.2	6.2
Gas (high)	6.1	6.7	7.7

Continued on page 12 ➲

Continued from page 11

renewable energy portfolio standard;
- a production tax credit for a small number of "first mover" plants to demonstrate cost and regulatory feasibility.

Safety

The report focuses on four safety issues: (1) reactor safety, (2) training of plant personnel, (3) terrorist attack, and (4) nuclear fuel cycle safety.

According to the study, new light water reactor plants (the predominant type of reactor) should be able to achieve a ten-fold reduction in the likelihood of a serious reactor accident, i.e., one event of core damage in 100,000 reactor-years. That said, it stresses the importance of a management committed to safety, and a skilled work force, neither of which is a given in the global context. It observes that the extent to which nuclear plants can be protected from terrorist attack is also unresolved. Finally, the authors conclude that little is known about the safety of the overall fuel cycle (which refers to all activities that occur in the production of nuclear energy, including ore mining, waste management, etc.), beyond reactor operation.

Recommendations

The report's recommendations include:
- government development of the capability to analyze full life-cycle health and safety impacts of the fuel cycle;
- focusing reactor development on those types of reactors that can maximize safety.

Waste management

The report dubs the management and disposal of spent fuel from nuclear power plants "one of the most intractable problems" facing the industry. The authors believe that geological disposal is technically feasible, but yet to be demonstrated. This is their view of the astonishing magnitude of the problem:

> The global growth scenario, based on the once-through fuel cycle, would require multiple disposal facilities by the year 2050. To dispose of the spent fuel from a steady state deployment of one thousand 1 GWe reactors of the light water type, *new repository capacity equal to the nominal storage capacity of Yucca Mountain would have to be created somewhere in the world every three to four years* (emphasis added).

The report notes that the difficulties of disposal and the desire to reduce the long-term risks from nuclear waste prompt interest in closed fuel cycles, as opposed to open or "once through" cycles. Closed fuel cycles involve the reprocessing of spent nuclear fuel to separate weapons-usable plutonium and to enrich uranium for further use. (A word on definitions: the report characterizes open and closed fuel cycles as "classes," both of which can involve a variety of "reactor types," e.g., light water reactors, supercritical water reactors, molten salt reactors.)

However, one of the study's central conclusions is that approaches that would separate plutonium and other fission products from the spent fuel are not justified. The authors believe that closed fuel cycles involving reprocessing of spent fuel may be (but are not clearly) preferable in terms of waste management considerations, but that serious disadvantages related to cost, environmental risk and proliferation predominate.

Note that Russia, the United Kingdom, France, Switzerland, Belgium, Germany and Japan make use of closed fuel cycles, involving the reprocessing of spent nuclear fuel. Since the mid-1970s, U.S. energy policy has rejected the reprocessing of spent fuel. However, according to the Congressional Research Service, the Department of Energy's Generation IV program is focusing on six advanced designs, some of which would involve the reprocessing of spent fuel.

Recommendations

Among the recommendations are:
- a research program to determine the viability of deep borehole (as opposed to mined repository) waste disposal;
- replacement of the current approach to spent fuel storage at reactor sites with a network of centralized facilities for storing spent fuel in the short term (i.e., several decades).

Nonproliferation

The authors' view is that nuclear power should not expand unless the risk of proliferation of the global growth scenario for commercial nuclear power is acceptably small.

The risk of nuclear weapons proliferation associated with nuclear power derives from the possible unauthorized acquisition of plutonium or highly enriched uranium, and transfer of the expertise relevant to the production of this weapons-usable material. The reprocessing system currently used in a number of countries, which involve separation and recycling of plutonium, presents "unwarranted" proliferation risks. The open fuel cycle minimizes the risk of plutonium proliferation; however, since it typically requires enriched uranium, it does not entirely eliminate the concern.

After September 11, the threat of acquisition of a crude nuclear explosive by a sub-national group of terrorists has arisen, even though these groups are currently unlikely to be able to produce nuclear materials themselves. Once the materials are in hand, construction of the explosive device is relatively straightforward.

Continued on page 13 ➲

Continued from page 12

The study concludes that the current international safeguards regime under the Nuclear Nonproliferation Treaty is inadequate to the task. The "frayed" nonproliferation regime would do the job only if it were markedly strengthened, and if the global growth scenario built primarily upon the once-through reactor fuel cycle. Nonproliferation would also require long term geological isolation.

Recommendations

The response should include: 1) strengthening of the International Atomic Energy Agency's focus on its safeguards function, including enhanced inspection authority; and 2) research and development that includes explicit analysis of proliferation risks and the minimization of such risks.

Insights:

It is difficult to characterize *"The Future of Nuclear Power"* as endorsing or rejecting a future for nuclear power. On the one hand, it cites the concern about global warming as requiring continued consideration of the nuclear option. On the other hand, it describes overwhelming challenges.

The global growth scenario that the authors posit is huge: a threefold increase in worldwide nuclear generating capacity. The challenges they describe should be understood in this context, and not as sounding the death knell for any individual plant or proposal.

That said, the magnitude of the challenges the authors describe in the global growth scenario is truly daunting. Nothing makes that more clear than their description of the waste disposal problem: the need to create new repository capacity equal to the nominal storage capacity of Yucca Mountain somewhere in the world every three to four years.

The report's preference for once-through, as opposed to closed, fuel cycles is central. Although, the closed fuel cycle may (the authors stress "may") be preferable from the standpoint of waste disposal, its disadvantages include cost, safety and, particularly, proliferation.

Recent news reports (about, e.g., North Korea, Pakistan, Libya) make the study's references to the "frayed" nonproliferation regime all the more credible. In light of the fact that Russia, Japan, and several countries in western Europe all reprocess spent nuclear fuel, one cannot but wonder about the extent to which that genie is out of the bottle.

EPA Finalizes Phase II of the NOx SIP Call

In April 2004, after much delay, EPA finalized Phase II of the NOx SIP call. The story is short on plot but long on details, which we address here.

Legal Background

Recall that in October 1998, EPA published its final NOx SIP call rule, which was immediately challenged by a number of states, as well as some industry and labor groups (with the Clean Energy Group intervening on EPA's behalf). In March 2000, the D.C. Circuit Court of Appeals issued its decision in Michigan v. EPA (which concerned only the one-hour basis for the SIP call). The court ruled in favor of EPA on most, but not all, issues.

Phase I versus Phase II

As a result of the numerous EPA and court actions on the lawsuits, states were required, by October 2000, to submit SIPs for *only the portions of the NOx SIP call upheld by the Court* ("Phase I"). These "Phase I" SIPs covered all of the NOx SIP call requirements *except for* a small part of the electric generating unit (EGU) and large internal combustion (IC) engine portions of the budget (issues on which the Court ruled against EPA). SIPs were due at that time only for 19 states and the District of Columbia, due to the Court's remanding and vacating the inclusion of Wisconsin, Georgia, and Missouri. These Phase I SIPs included provisions for states to participate in the NOx Budget Trading program for the 19 states and the District of Columbia. The compliance date for sources subject to the trading program was May 1, 2003 for sources in northeastern states covered under the OTC NOx Budget Trading Program and May 31, 2004 for sources in the remainder of the 19 states. "Phase II" SIPS are those that cover the issues in the rule on which the court ruled against EPA. These are addressed in the April 2004 NOx SIP call rulemaking (discussed below).

What Did EPA Finalize in April 2004?

The April 2004 final NOx SIP call rulemaking includes provisions:

- finalizing the definition of EGU as applied to certain small cogeneration units;
- setting the control levels for stationary IC engines;
- excluding portions of Georgia, Missouri, Alabama and Michigan from the SIP call;
- revising statewide emissions budgets in the SIP call to reflect the first three issues above;
- setting a SIP submittal date;
- setting the compliance date for implementation of control measures; and

Continued on page 14 ➲

Continued from page 13

- excluding Wisconsin from the SIP call requirements.

Definition of EGU as applied to certain small cogeneration units

For purposes of the NOx SIP call and the Section 126 rule, EPA finalized a change to the EGU definition regarding small cogeneration units. This results in an EGU definition that excludes certain small cogeneration units. Such units are now included in the non-EGU definition. However, EPA anticipates that few, if any, small cogeneration units will change classification as a result of this change. EPA is also finalizing some minor changes to the categorization of units under the SIP call definition of EGU (based on dates of commencement of operation).

Setting the control levels for stationary IC engines

EPA finalized a control level of 82 percent for natural gas-fired lean-burn IC engines. According to EPA, because the vast majority of large natural gas-fired IC engines are lean burn, the Agency is applying the 82 percent reduction to all large natural gas-fired IC engines for the purposes of setting that portion of the state NOx budgets. For other IC engine subcategories (diesel and dual fuel), EPA is using 90 percent control, as proposed. Note that although IC engines are subject to the SIP call, they are *not* part of the *NOx Budget Trading Program* under the SIP call; therefore, they will not be participating in trading with EGUs.

Excluding portions of Georgia, Missouri, Alabama and Michigan from the NOx SIP call

Before turning to the exclusion of partial states, it is useful to provide some background on the Ozone Transport Assessment Group (OTAG) modeling analyses that EPA used to determine contribution to downwind attainment for the SIP call rulemaking. In this modeling, OTAG split the eastern part of the U.S. into "fine grid" and "coarse grid" portions. The OTAG analysis found that emission controls modeled in the entire coarse grid made little contribution to high one-hour ozone levels in the downwind ozone problem areas of the fine grid.

Now turning to Georgia and Missouri: A lawsuit against EPA alleged that EPA's record supported inclusion of only the fine grid portions of those two states (eastern Missouri and northern Georgia), and the court vacated EPA's inclusion of Georgia and Missouri in the SIP call. In its April rule, EPA finalized the inclusion in the SIP call of only the fine grid portions of Georgia and Missouri. Because similar fine grid/coarse grid issues apply to Alabama and Michigan, EPA finalized the inclusion of only the fine grid portions of these states as well. EPA also revised the NOx budgets for Georgia, Missouri, Alabama and Michigan to reflect reductions in only the fine grid portions of the states.

Revising statewide emissions budgets in the NOx SIP call

EPA revised the statewide emissions budgets to take into account the changes to the EGU definition, the IC engines control levels and the inclusion of only parts of Georgia, Missouri, Alabama and Michigan. These new budgets are the Phase II budgets.

In addition, for states with a May 31, 2004 Phase I compliance deadline, the rule provides that compliance supplement pool (CSP) allowances can be used until September 30, 2005, which means they can be used for the first two control periods sources are subject to the SIP call. Similarly, for sources with a May 1, 2007 compliance date (discussed below), CSP allowances can be used until September 30, 2008. The rule also includes revised CSP values for Georgia, Missouri, Alabama and Michigan, to reflect that only part of the states are subject to the SIP call.

SIP submittal date

EPA has set April 1, 2005 as the SIP submittal date for SIPs meeting the Phase II NOx budgets. This means that 19 states and the District of Columbia will submit SIPs to meet the reductions required by the Phase II increment, while Georgia and Missouri will submit SIPs that meet the entire SIP call, since they were not required to submit Phase I SIPs. Although Alabama and Michigan are partial states in the program, their SIPs were not delayed by the court actions and they were among the 19 states that had to submit Phase I SIPs in 2000.

The compliance date

The Phase II NOx SIP call compliance date is May 1, 2007. Note that this applies to all sources in Georgia and Missouri as well. EPA had proposed a compliance date for these states of May 1, 2005, but the date has been moved to 2007 due to delay in publishing the final rule.

Excluding Wisconsin from the NOx SIP call requirements

The court held that EPA erroneously included Wisconsin in the SIP call, so EPA is removing the entire state from the requirements of the one-hour basis of the SIP call.

Additional information

Note that EPA is now evaluating lifting the stay on the eight-hour findings in light of recent EPA actions on the eight-hour ozone standard. However, none of the actions in the April 2004 SIP call Phase II final rule (based on the *one-hour* findings) have any effect on the requirements of the SIP call for states under the *eight-hour* ozone standard.

Note on Growth Factors Case

In resolution of a separate legal issue, in April 2004 the D. C. Circuit upheld the EGU growth factors EPA used in writing the SIP call and Section 126 rules. In doing so, the court rejected challenges by West Virginia, Illinois, and several businesses and other groups, which had claimed that EPA's growth projections for emissions through 2007 were arbitrary.