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Dockets: UE-200304 for electric, UG-200305 for natural gas

Comments of Jim Lazar, 1907 Lakehurst Dr. SE, Olympia, WA 98501

Jim Lazar is an Olympia resident, a retired Senior Advisor to the Regulatory Assistance Project, a past consultant to the WUTC and to Public Counsel, and the author of several important handbooks on the regulation and management of the electric utility sector.

The key publications which relate to this docket and these comments include:

a) Electricity Regulation in the United States: A Guide (used as a text now in at least 20 colleges and universities)
b) Incorporating Environmental Costs in Electric Rates (attached to these comments, and referred to by page in the comments below).

These comments focus on two narrow aspects of the electric and gas IRPs:

1) The treatment of the Social Cost of Greenhouse Gas Emissions; and
2) The treatment of demand response resources

There are many other important elements in the Plan, and other comments from James Adcock, the Coalition of Eastside Neighborhoods for Sensible Energy, and the hundreds of people who submitted written and oral comment in February should be given careful attention.

1) The treatment of the Social Cost of Greenhouse Gas Emissions

Washington has required consideration of GHG emissions costs in the IRP for many years, but the passage of the Climate Commitment Act changes the importance of these and the methods that should be used. Specifically, GHG emissions should always be considered a dispatch cost of either burning a fossil fuel to generate electricity, or consuming a therm of natural gas.

Beginning in 2023, assuming that the Act takes effect, GHG emissions will carry a direct cost. PSE will have to secure emission allowances for all of its natural gas and electricity emissions. Those that are not required can be auctioned into the market to directly reduce costs. This changes the appropriate method to a dispatch method, where GHG costs are treated as an incremental short-run marginal cost of using fossil energy.

The method used by PSE in its IRP, estimating GHG costs exogenously and then treating these as a fixed cost, is not appropriate. If one treats GHG costs as a fixed cost, then the hourly, seasonal, and annual modeling ignores this very real cost in the decision of what resources to dispatch. There are several problems with this:

a) More fossil energy will be dispatched, rather than purchase of non-emitting energy (when it is available) and the storage needed to shape that non-emitting energy. This misrepresents the actual market in which resource operation and dispatch will occur in the future.

b) Customer bills will be unnecessarily increased by the limited supply of non-emitting resources acquired under the plan, leading to the dispatch of fossil energy when lower cost resources (including GHG costs) are available;

c) Poor planning and acquisition of storage, demand response, and other measures that shape, shed, and shift load into lower-cost lower-emission hours will occur.

d) Errors will occur in cost allocation and rate design if GHG costs are not treated as variable costs. This is of particular concern given the rigid cost allocation methodology that the Commission adopted in a 2020 rulemaking. See pages 35-38).

I recommend that the utility be placed at risk for any environmental costs not fully analyzed and incorporated into the hourly modeling and the resource procurement process. See pages 21 – 25).

The need to accurately reflect environmental costs in hourly dispatch analysis has become more important as the 8th Power Plan comes to fruition. I serve on the Council's Conservation Resource Advisory Committee. We have been told by the Council staff that the modeling is showing large numbers of hours of negative prices (periods when non-dispatchable renewable energy floods the market) and other hours of high cost (when fossil units are used). The draft Plan, at this point in time, includes ONLY energy efficiency and renewable energy as future resources; there is zero acquisition of fossil resources, even peakers, planned. If emission costs are not treated as dispatch costs in PSE modeling, PSE results will be inconsistent with the Plan.

Resource planning, procurement, dispatch, and pricing should always be done with a clear attention to long-run marginal costs. Erroneously classifying emission costs as a "fixed cost" will result in errors throughout the process, and ultimately, higher costs to residential consumers, schools, government agencies, and businesses in Washington.

2) The Treatment of Demand-Response Resources

PSE continues to "silo" the benefits of demand response resources, such as grid-integrated water heaters, ice-storage air-conditioners, customer-side electricity storage, and smart electric vehicle charging. Each of these types of resources provides benefits in the form of generation capacity, bulk energy, transmission costs, distribution costs, line losses, emissions avoidance, resilience, and avoided reserves.

If properly analyzed, these types of resources could help avoid new generation, new transmission, distribution upgrades, and customer premises capacity upgrades. The "value stack" of these benefits makes them very cost-effective.

PSE continues, however, to examine these resources against discrete needs, not against composite needs. For example, the Commission has received evidence that smart water heaters alone could have eliminated the need for the “Energize Eastside” transmission investment. But these resources are not cost-effective measured against a single metric; they are only cost-effective when the full panoply of benefits is considered simultaneously.

I urge the Commission to direct PSE to incorporate all benefits of demand response resources in both the IRP process and the resource procurement process.

The state of Vermont offers a good lesson in this. Each year, the Commission identifies geographic nodes where energy efficiency and demand response have the highest values. These locales are targeted for resource acquisition. Had this been done a decade ago, as recommended by Public Counsel in a prior IRP docket, it is likely that tens or hundreds of millions of dollars of generation capacity, transmission capacity, and distribution capacity costs could have been avoided.

Respectfully submitted,

Jim Lazar

Energy solutions for a changing world

Incorporating Environmental Costs in Electric Rates

Working to Ensure Affordable Compliance with Public Health and Environmental Regulations

Authors
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October 2011

Acknowledgements

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Foreword

BY RICHARD SEDANO
Director of U.S. Programs, Regulatory Assistance Project

It has always been part of a utility regulator's job to weigh the relative merits of utility company requests to include certain costs in rates. Recently, with the potential for requests associated with Environmental Protection Agency (EPA) regulatory compliance costs with significant price tags aimed at consumers across the United States, RAP concluded that there would be value in focusing on this topic.

With various strategies and compliance choices facing companies over the next several years, regulators will want an acute sense of how to identify, assess, and approve both effective and cost-effective company strategies. Furthermore, regulators will need to determine how these costs, once approved, will be included in rates, and what incentives are best put into place to ensure that company management will control costs so that customer rates and bills over time stay as low as possible.

Moody's recently observed:

> *The credit risk factors associated with energy and climate legislation have existed for decades and managing these risks are considered a core competency for all utility operators, whether they are regulated or un-regulated, public or privately-owned.*[1]

Although utility operators have this awareness, utility regulators will benefit from deeper understanding of these challenges and choices.

Following up on RAP's July publication of *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance,"*[2] this paper, *Incorporating Environmental Costs in Electric Rates: Working to Ensure Affordable Compliance with Public Health and Environmental Regulations,* takes the next step and explores issues associated with potential rate effects and rate treatment of utility company compliance choices. We hope that this paper will help regulators as they work through these issues.

1 Moody's Investor Service, 2011.

2 Farnsworth, 2011.

1. The Need for Comprehensive Analysis of Aging Power Plants

Many of us share the experience of owning an older car that requires one repair after another, with the cumulative cost far exceeding the value of the vehicle. Power plants can be similar, except the costs are measured in millions and even billions of dollars, not thousands. The question is whether retrofit or replacement makes more sense.

Regulators will need to determine what costs should be allowed for cost recovery, what costs should be rejected, and how to treat the remaining investments in power plants that are no longer economical to revamp.

The purpose of this paper is to give utility regulators an appreciation for the breadth of issues that may cause cost impacts on fossil-fuel power plants over the coming decades. The paper begins with a brief recital of major forthcoming public health and environmental regulations for power plants. It identifies some of the costs of compliance with these existing and potential regulations. It then turns to how these costs will likely be presented to utility regulators and discusses how regulators should evaluate them. Regulators will need to determine what costs should be allowed for cost recovery, what costs should be rejected, and how to treat the remaining investments in power plants that are no longer economical to revamp. It concludes with a discussion of how emission management costs should be reflected in retail rates.

The United States is served by a fleet of nearly 1,500 coal-fired power plants, which provide over 300,000 megawatts (MW) of generating capacity and produce nearly half of the country's electricity. More than half of the coal-fired plants in the country were built before 1970; they are already at or beyond the end of their original economic life.[3]

Many of these older plants (and some newer ones) lack modern air and water pollution control devices and have poor management of combustion residuals, and none captures carbon dioxide (CO_2) emissions. Retrofit costs to control pollution and carbon emissions can be extremely expensive, often far more than the current investment in the plants, and in some cases, more than the cost of replacing the units with energy efficiency or new generation. Utility regulators should take a comprehensive view—evaluating long-term resource alternatives for meeting environmental and reliability requirements—when they consider requests from regulated utilities for investment in and cost recovery for retrofit measures, or for approval to dispose of these units. The alternative could be piecemeal expenditures over time that exceed the value of a new power plant—the equivalent of a $50,000 restoration of an aging Chevy Caprice.

Several recent studies have estimated that as much as 78,000 MW of power plants may be retired over the next decade as utilities examine plant economics in light of age, emission control strategies and replacement power costs.[4] If the potential for future CO_2 regulation were considered, this total would rise. Reasoned decisions about which power plants should be renovated, which should be mothballed (deferring a decision to a later date), and which should be retired include consideration of the relevant risks.

About half of these power plants are owned by investor-owned utilities subject to state utility commission regulation; these are the primary focus of this paper. Some plants are owned by municipal and cooperative utilities; their local regulators are city councils, public power district

3 U.S. Energy Information Administration, 2008.

4 For example, see several studies cited at Farnsworth, 2011, p. 24; see also Miller, 2011.

boards, and cooperative boards. The same principles apply to these regulators as do those we discuss for state regulators. Some plants are owned by non-regulated merchant generators, industries, tribal authorities, and others; these owners will need to develop their own appropriate criteria to evaluate the future economic viability of their units.

This need for long-range thinking and comprehensive analysis is illustrated by an industry press article about the Four Corners coal plant in New Mexico:

> *The Environmental Protection Agency is proposing that the most stringent pollution control equipment available be added to the 2,060-MW Four Corners plant, a move that adds to the challenges facing the generating station in northwestern New Mexico. To improve visibility in the Four Corners region, EPA wants the plant's owners to install selective catalytic reduction [SCR] equipment to the plant's five units, which could cost roughly $730 million to $890 million.*
>
> …
>
> *However, both the Four Corners and Navajo power plants face various difficulties beyond the possible requirement that they add SCR equipment. Other pending environmental regulations that would affect the plants include tougher restrictions on mercury and carbon dioxide emissions as well as coal combustion [residuals] requirements…*[5]

In recent years, utilities such as Duke Power, Exelon, and the Tennessee Valley Authority have announced retirement of more than 20 older coal-fired plants because they are uneconomical. In many cases, the operating costs alone are too high; in others, the cost of bringing them up to modern performance and environmental standards is excessive compared with alternative power and energy efficiency options.[6]

A comparison of the history of two power plants in the West shows the value of comprehensive analysis. The Centralia and Mohave plants were both built in the early 1970s, both are about the same size, and both originally owned by consortia of utilities. Their destiny, however, differed.

Centralia: Washington

The Centralia power plant, located between Seattle and Portland, was built in I972 by a group of electric utilities.

In 1998, the owners agreed to install scrubbers for sulfur dioxide (SO_2) to reduce haze at Mt. Rainier National Park. In exchange, the state of Washington agreed to long-term tax breaks for the plant owner.

A few years later, after the plant was sold to a new owner, the coal mine serving Centralia was largely played out and the owner invested in rail system upgrades.

ln 2012, the owner is expected to install controls for mercury. The pending EPA rulemakings could require additional compliance-related expenditures. The Washington Legislature approved a subsidy package in April 2011 to enhance the economic viability of Centralia and protect the owners from future emission regulation costs.

There has never been a publicly available comprehensive review of the economics of any of these piecemeal upgrades and the viability of Centralia's continued operation.

Mohave: Nevada

The Mohave power plant, located near Laughlin, Nevada, was built in 1970 by a group of electric utilities.

In 1999, the owners executed a consent decree to either install SO_2 controls or close the plant by 2005.

In 2003, Southern California Edison approached the California Public Utilities Commission (CPUC) for approval of the preliminary engineering costs for the retrofit. After an extended hearing, the CPUC ordered a comprehensive review of the future of the Mohave project.

The Mohave Alternatives and Complements Study (MACS) was completed in 2005. It examined alternatives to a retrofit of Mohave, found a wide variety of cost-effective options, and at the conclusion of the study, the Mohave plant was closed permanently on Dec. 31, 2005.

5 Platts, October 11, 2010.

6 CoalSwarm, "Existing U.S. Coal Plants," 2011.

The Mohave Alternatives and Complements study (MACS), prepared at the direction of the CPUC, is an excellent example of the type of comprehensive analysis that regulators should insist on as a condition of emissions compliance investment at an existing power plant.[7] The study's table of contents provides a sense of the breadth of the MACS analysis (Fig. 1).

Figure 1

Mohave Alternatives and Complements Study Table of Contents

I. Existing Plant
II. Integrated Gasification / Combined Cycle Technology
III. Solar Technology
IV. Wind Technology
V. Natural Gas Combined Cycle Technology
VI. Demand Side Management / Energy Efficiency Technology
VII. Other Renewable Energy Technology
VIII. CO_2: Sequestration
IX. Tribal Issues
X. Financial Issues
XI. Generation and Demand Issues
XII. Transmission Issues

In theory, a merchant power plant owner will always have an incentive to consider the entire picture. Merchant plants sell power into a competitive market, and if the life-cycle revenues will not exceed the life-cycle costs, they will lose money. This is not necessarily the case for regulated utilities, which have the opportunity to earn a fair rate of return on their allowed rate base—that is, their investment in a utility plant that serves customers as approved by the regulator. A regulated utility might be allowed to collect more than the power is worth over time, if permitted to do so by a regulator that allows incremental decisions and gradual cost recovery. This can be true even if the individual decisions are cost-effective when viewed in isolation. When considering the investment in pollution controls, regulators therefore should look at the totality of the costs that might be required for multiple investments in order to ensure the prudency of the expenditures.

7 Synapse Energy Economics, 2006.

2. New and Forthcoming Public Health and Environmental Regulations

To ensure the reasonableness of pollution control investments, regulators should be aware of what areas the new and forthcoming public health and environmental regulations cover.

In response to legal obligations imposed by Congress and the federal courts, the United States Environmental Protection Agency (US EPA) is in the process of promulgating a suite of public health and environmental rules that will have a significant impact on investment decisions to be made by the electric sector. What follows is a brief discussion of these newly proposed and forthcoming EPA rules.[8] (A more complete description is found at Appendix 2.[9]) These descriptions are intended as illustrations of these rules as of Fall 2011; thus, readers should consult the latest administrative enactments, statements of agency policy, and judicial decisions for a more complete picture of their status.

The following rulemakings—one being developed under the Clean Water Act, three under the Clean Air Act (CAA), and one under the Resource Conservation and Recovery Act (RCRA)—are in various stages of consideration, adoption, and implementation:

- *316(b) Cooling Water Rule*
- *Wastewater Rule*
- *Cross-State Air Pollution Rule*
- *Mercury/Air Toxics Rule*
- *New Source Performance Standards (CO_2)*
- *Coal Combustion Residuals Rule*

316(b) Cooling Water Rule

As part of a settlement agreement with environmental groups in litigation under the Clean Water Act, the EPA will issue regulations designed to "reduce injury and death of fish and other aquatic life" caused by cooling water intake structures at existing power plants and factories."[10] The proposed 316(b) rule will establish requirements for existing facilities that (a) withdraw more than 2 million gallons per day of water from waters of the United States, and (b) use at least 25% of the water they withdraw exclusively for cooling purposes. The EPA estimates that 670 of these facilities are power plants, including both coal and natural gas-fired units.[11] The final rule must be signed by July 27, 2012 under the terms of a settlement agreement, and compliance deadlines for fossil plants are in 10 years and for nuclear facilities in 15 years.[12]

Wastewater Rule

The Wastewater Rule (1982) focuses on the steam electric subcategory of all electric generating activities, including fossil-fueled (coal, oil, gas) power plants.[13] A major focus of the Wastewater Rule is on toxic pollutants released into wastewater and ash ponds as part of the flue gas desulfurization (FGD) process. Currently guidelines cover suspended solids, oil and grease from ash ponds, and FGD discharges. Although some of the newest power plants have zero liquid discharge (ZLD) systems, most existing power plants release substantial amounts of water used

8 To address rate implications, this paper focuses on a limited list of regulatory actions. Readers should be aware, however, that the electric industry is subject to other public health and environmental regulations (e.g., likely changes to ground-level ozone standards in the 2013-14 timeframe).

9 For a more complete discussion of forthcoming EPA regulations, see Farnsworth, 2011.

10 Federal Register, April 20, 2011, pp. 22174-22288.

11 U.S. Environmental Protection Agency, March 2011.

12 U.S. Environmental Protection Agency, March 2011.

13 This discussion is based in part on a presentation by Hewitt, 2010.

in boilers, cooling systems, and pollution control systems back into the environment. Unregulated pollutants are present in ash ponds, and related discharges include metals that are bioaccumulative (e.g., mercury, selenium, arsenic), nutrients (e.g., nitrates, ammonia), and chlorides.

According to the EPA, the schedule for the development of a Wastewater Rule requires the EPA to collect technical and financial information for analysis, an effort that is now underway. No rule has been proposed, but the EPA intends to issue proposed regulation in mid 2012 and a final rule in late 2013. Dischargers are likely to be required to apply for National Pollutant Discharge Elimination System (NPDES) permits. Compliance is expected to start 3 to 5 years after the final rule, in 2016 to 2018.

Cross-State Air Pollution Rule

In the Cross-State Air Pollution Rule (CSAPR), the EPA seeks to "limit the interstate transport of emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) that contribute to harmful levels of fine particle matter (PM2.5) and ozone[14] in downwind states."[15] These emissions—referred to as "criteria pollutants" under the federal CAA—are carried downwind as SO_2 and NOx or, after being transformed in the atmosphere, as fine particles or ozone. By reducing emissions in upwind states, air quality in downwind states is improved, thereby helping downwind states meet National Ambient Air Quality Standards (NAAQS). The EPA published the final rule in June 2011.

Mercury/Air Toxics Rule

The "National Emissions Standards for Hazardous Pollutants," commonly referred to as the "Mercury/Air Toxics Rule," is the first national standard to reduce mercury and other toxic air pollution from coal- and oil-fired power plants.[16] Pollutant emissions that the rule covers include mercury, arsenic, other toxic metals, acid gases, and organic air toxics such as dioxin. The final rule is expected in November 2011.

New Source Performance Standards (GHG)

The CAA requires the EPA to establish categories of major polluters and to develop New Source Performance Standards (NSPS) for new or modified sources in each category. In December 2010, the EPA entered into a settlement in which it agreed to develop NSPS for greenhouse gases (GHG) from new and modified electric generators and emission guidelines for existing electric generators. On September 14, 2011, the EPA announced that it would miss the September 30, 2011 deadline for the proposed rule and stated that it would announce a new timetable in the near future.[17]

Coal Combustion Residuals Rule

The EPA proposed a rule on Coal Combustion Residuals (CCRs) from electric utilities in June 2010 but has not set a date for a final rule.[18] CCRs are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and FGD materials. In 2008, over 136 million tons of CCRs were produced in the United States. This waste is currently disposed of in various ways. It is placed in approximately 300 CCR landfills and in 584 surface impoundments at approximately 495 coal-fired power plants across the nation. It is also placed in mines or is "beneficially" used (e.g., in building materials.)[19]

14 Ground-level ozone is a pollutant created through the interaction of NOx, volatile organic compounds or "VOCs," and sunlight.

15 Code of Federal Regulations Title 40, Parts 51, 52, 72, 78, and 97.

16 Federal Register, May 3, 2011.

17 Harder, 2011.

18 Federal Register, June 21, 2010.

19 According to the U.S. EPA, "[b]eneficial use refers to use of material that provides a functional benefit — that is, where the use replaces the use of an alternative material or conserves natural resources that would otherwise be obtained through extraction or other processes to obtain virgin materials;" see U.S. Environmental Protection Agency, "Frequent Questions: Coal Combustion Residues - Proposed Rule," 2011.

Figure 2

Major EPA Rulemakings Impacting Power Plants[20]

Proposed Regulation	Targeted Pollutant	Control Options	Schedule
316(b) Cooling Water Rule	Cooling water intake design	Intake design upgrades: cooling water intake structures	• Proposed rule April 20, 2011 • Final rule July 2012 • Facility compliance due by 2020
Wastewater Rule	Wastewater toxic metals	Treatment or zero discharge	• Proposed rule July 2012 • Final rule January 2014
Cross-State Air Pollution Rule	Reduced downwind contribution to ozone and PM2.5 non-attainment	NOx removal: selective catalytic reduction (SCR) 70-95%; selective non-catalytic reduction (SNCR) 30-75%; SO_2 removal: scrubber ≥95%; dry sorbent injection <70%	• Final rule July 2011 • Unit compliance due in stages: • Phase I begins January 2012 • Phase II begins January 2014 • Phase II CSAPR rulemaking 2012?
Mercury/Air Toxics Rule	Hazardous air pollutants (Hg, HCl, metals, organics)	Hg removal: fabric filter baghouse (FF) -activated carbon injection (ACI) 80-90%; Scrubber-SCR co-benefit >90%	• Proposed rule May 3, 2011 • Final rule due November 16, 2011 • Unit compliance due by November 2015 (3 years, case-by-case 1-year extension)
New Source Performance Standards for Greenhouse Gases	Greenhouse gases	CCS, market-based approaches	TBD
Coal Combustion Residuals Rule	Coal combustion waste disposal	Phase out wet surface impoundments (ash ponds); composite liners; other changes for disposal sites	• Proposed rule March 2010 • Final rule TBD • Ash pond closures 5-7 years after final rule (2016-2018)

Abbreviations: *CCR, carbon capture and storage; CSAPR, Cross-State Air Pollution Rule; HCl, hydrochloric acid; Hg, mercury.*

20 Based on Silva, 2011.

Potential Costs of Pollution Controls

Meeting the requirements of these regulations will call for significant investment in compliance technology. We consider several examples here, one under the Clean Water Act and two under the CAA.

Although a generator might comply with cooling regulations by installing screens or nets or by reducing cooling water intake velocity, many generators will have to construct a cooling tower or towers at their facilities. Modelers have estimated the costs of cooling towers to be directly influenced by the physical layout of a plant and the rate at which it pumps water. The North American Electric Reliability Corporation (NERC) has estimated the cost of cooling technology within a range of $170 to $440 (2010 dollars)/gallons per minute for typical plants and higher for more constrained locations (i.e., plant sites with insufficient space to locate cooling towers).[21] Edison Electric Institute's estimates range from $319 to $459/gallons per minute, for fossil plants and nuclear plants, respectively.[22]

Likewise, investment required by the Cross-State Air Pollution and Mercury/Air Toxics Rules can be expected to be significant and, depending on the generation unit, to require the installation of a combination of controls. Figure 3 depicts the types of controls that are likely to be installed in response to these two air rules.

It should be noted that some of these technologies can help generators meet reduction requirements from both rules. For example, FGD can be used to reduce SO_2 emissions required by the CSAPR as well as the emission of acid gases and mercury required by the Mercury/Air Toxics rule.[23]

Figure 4 shows some of the key investments that may be incurred to meet the criteria and hazardous pollutant standards discussed previously; it does not show the operating costs or the power losses for each of these measures. CO_2 compliance is not included in this diagram but is discussed in Section 4.

Figure 3

Compliance Technology for the Cross-State Air Pollution and Mercury/Air Toxics Rules

Pollutant	Compliance Technologies
NOx	SCR/SNCR
SO_2	FGD/DSI
Mercury	ACI
Particulates	Fabric Filters (plus ACI/DSI)

Abbreviations: *SCR, selective catalytic reduction; SNCR, selective non-catalytic reduction; FGD, flue gas desulfurization; DSI, dry sorbent injection; ACI, activated carbon injection*

21 North American Electric Reliability Corporation, October 2010, p. 48.

22 ICF International, January 2011, Appendix A.

23 For a more complete discussion of compliance technologies, see Farnsworth, 2011, pp. 26-27, 36, Appendix 2.

Figure 4

Representation of Air Pollution Controls[24]

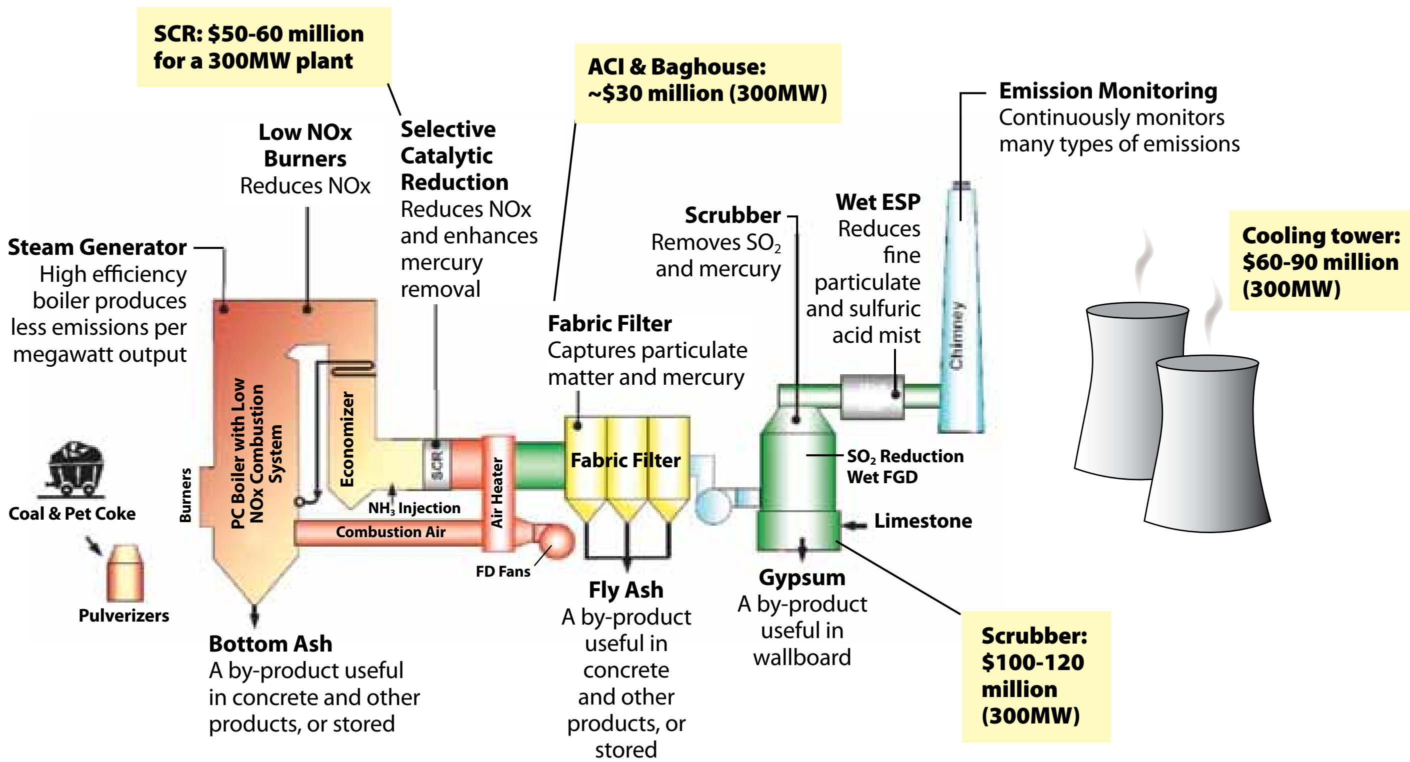


Figure 5 provides a representation of these types of air pollution controls and their related capital and fixed and variable operation and maintenance (O&M) costs as applied to a 500-MW coal unit. Because of the economies of scale associated with retrofit installations, the larger the unit, the lower the likely capital costs per kW and fixed O&M costs per MW of capacity. Also, the larger the unit, the higher the variable O&M costs per MWh of output.

Figure 5

Pollution Control Retrofit Costs[25]

For a Representative 500-MW Coal Unit in the PJM Regional Transmission Organization Interconnection

Control Technology	Type of Emissions Controlled	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)
FGD	SO_2	$501	$8,150	$1.81
DSI	SO_2	$40	$590	$7.92
SCR	NOx	$197	$720	$0.66
SNCR	NOx	$19	$260	$1.33
Fabric Filter + ACI	Particulates	$155 + $9	$630 + $40	$0.15 + $0.93

24 The Brattle Group, December 2010. As with other figures provided in this paper, this figure is intended as an illustration. Individual plants, because of site-specific factors, will come with their own costs.

25 PJM Interconnection, August 26, 2011, Table 2.

Figure 6 shows a range of costs for pollution control retrofits for coal-fired units in PJM associated with the Cross-State and Mercury/Air Toxics Rules. Although factors associated with individual plants will drive actual retrofit decisions, both Figures 5 and 6 highlight the likelihood that smaller and less efficient plants will be more challenged to make the case for investing and retrofitting. As noted by PJM, "higher costs mean that small units will require greater revenues per MW of capacity to pay for pollution control retrofits."[26]

Figure 6

Pollution Control Retrofit Cost Estimate Ranges[27]

For Coal Generation in the PJM Regional Transmission Organization Interconnection

Control Technology	MW Size Range	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)
FGD Range ***(Average)***	28-1,300 MW ***(211 MW)***	$331-$1,149 ***($677)***	$1,580-$44,710 ***($12,100)***	$1.01-$3.81 ***($1.93)***
DSI Range ***(Average)***	43-1,320 MW ***(408 MW)***	$9-$273 ***($89)***	$170-$5,670 ***($1,780)***	$2.00-$15.54 ***($5.71)***
SCR Range ***(Average)***	16-554 MW ***(161 MW)***	$175-$427 ***($263)***	$550-$15,600 ***($4,130)***	$0.20-$1.41 ***($0.47)***
SNCR Range ***(Average)***	45 – 1,300 MW ***(256 MW)***	$11 - $136 ***($48)***	$140-$4,900 ***($1,190)***	$0.34-$2.16 ***($1.12)***
Fabric Filter + ACI Range ***(Average)***	16-1,320 MW ***(299 MW)***	$118-$468 ***($225)***	$520-$9,340 ***($1,190)***	$0.52-$1.59 ***($1.09)***

Combined Costs of Compliance for Combined Rules

The ultimate cost of compliance with the EPA's public health and environmental regulations will depend on the final form that these rules take and will vary from company to company, plant to plant, and region to region, depending on what controls are currently installed and what more are needed. Several analysts have prepared estimates of the cost of compliance, and the number of plants that may become uneconomical as a result of the rules.[28] None of these, however, also addresses the effect that CO_2 regulation may have on plant viability.

A retirement decision must compare the present value or levelized cost of a compliance strategy and operating an existing power plant with the least-cost alternative. That alternative may be increased operation of other existing power plants, construction and operation of new fossil or renewable power plants, investment in energy efficiency measures, or a combination of these.

Our purpose in this paper is not to discuss whether the rules are appropriate or needed, but rather to educate utility regulators as to the need for comprehensive analysis of retrofit costs so that reasoned decisions can be made on whether incremental retrofit expenditures should be approved. In some states, approval takes place before expenditures are made (preapproval), and in others, only after the utility has made investments and seeks to include those costs in rates in a general or other rate proceeding.[29]

A retirement decision must compare the present value or levelized cost of a compliance strategy and operating an existing power plant with the least-cost alternative. That alternative may be increased operation of other existing power plants, construction and operation of new fossil or renewable power plants, investment in energy efficiency measures, or a combination of these.

26 PJM Interconnection, August 26, 2011.

27 PJM Interconnection, August 26, 2011, Table 3.

28 For example, see several studies cited at Farnsworth, 2011, p. 24; see also Miller, 2011.

29 For an extended discussion of preapproval issues, see National Regulatory Research Institute, 2008.

3. What Kinds of Requests Will Regulators Likely See From Utilities?

Approximately half of the coal plants in the United States are owned by utilities subject to state regulation. The others are owned by a mix of federal agencies, Indian nations, consumer-owned utilities, industrial facilities, and non-utility generators. This section addresses how state utility regulators should consider requests related to retrofits and closures from the utilities they oversee.

Regulators should expect to receive piecemeal requests from utilities for preapproval and rate case approval of their investment in emission control measures at older power plants and the operating expenses associated with these emissions controls. Rather than seek approval for the full suite of improvements needed to address SO_2, NOx, hazardous air pollutants like mercury, CO_2, and other environmental compliance issues, it is likely that many applications will address only one pollutant at a time, so that the full picture of long-run costs is never before regulators in a single docket. To be fair, it may be that specifics of some of the future rules are not fully known at any point. A comprehensive analysis can include an estimate of future compliance costs for regulators to evaluate.

Some of these requests will likely seek recovery for emission management costs as part of a general rate case. In many cases, however, the requests will seek dollar-for-dollar recovery through adjustment clauses rather than consideration in general rate cases and inclusion in base rates.

Some requests will come in the form of preapproval requests for such things as budget approval, certificates of public convenience and necessity (CPCN), and integrated resource plan (IRP) proceedings. Other requests will come to regulators only after the expenditures are made in general or special purpose rate cases.

Regulators must insist on a full analysis of the effect of current and prospective environmental compliance costs and should also examine the residual public health and environmental damages before approving any investment. Failure to consider all prospective costs can result in incremental uneconomical decision-making.

In addition, regulators need to consider alternative ways to meet customer needs, environmental requirements, and reliability standards. Energy efficiency, demand response, and distributed generation need to be considered in addition to supply-side options. A full IRP analysis, similar to what the Oregon PUC required of Portland General Electric (PGE) before approving a plan for the Boardman plant is an example of this (see Section 5, below).

a. The Age of U.S. Coal-Fired Power Plants

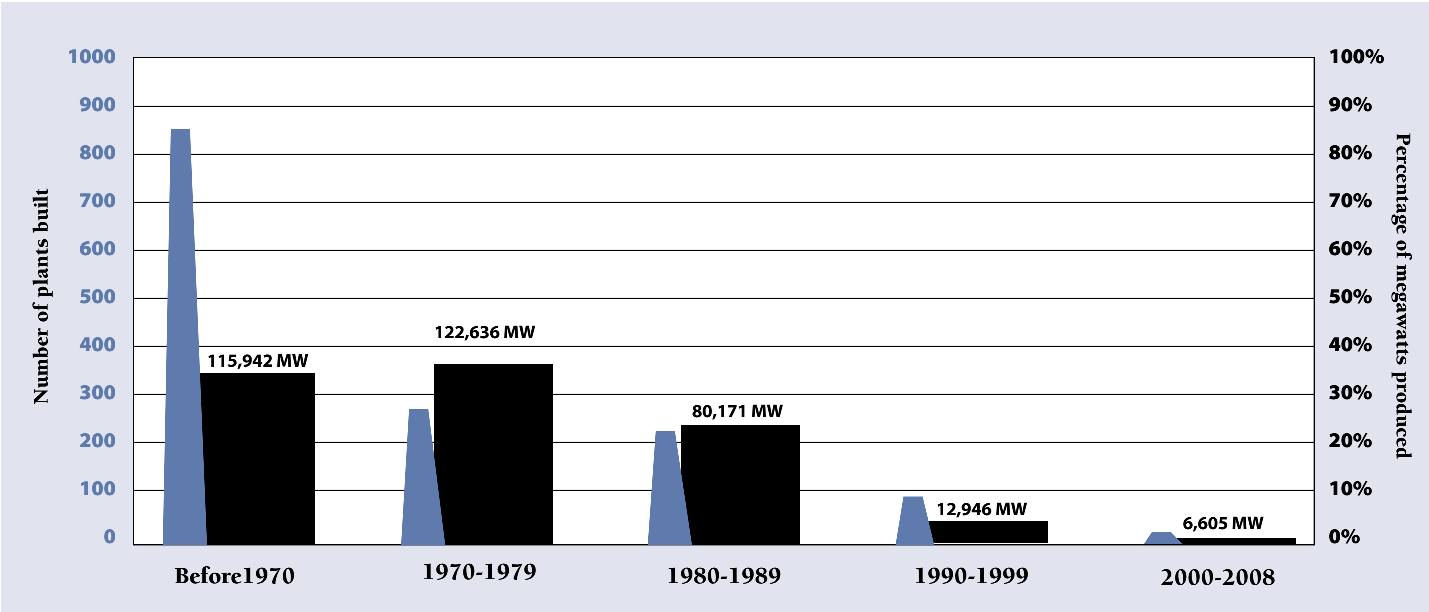
Figure 7 shows the age of coal-fired power plants in the United States. Generally, those built before 1980—about 70% of total existing capacity—were built without any modern pollution control equipment. Some have been retrofitted in the intervening years with some emission control equipment, but only one third of the coal capacity has SO_2 scrubbers.[30] The newest plants generally have the most sophisticated pollution control equipment and will be subject to the fewest additional regulations. The oldest plants—one third of the total capacity, most of which are more than 40 years old—will require very expensive renovation if they are to continue to operate. These are also generally smaller generating units, for which the lack of economies of scale mean that retrofit will be less cost-effective than for the newer, larger generating units.[31]

30 CoalSwarm, "Scrubbers," 2011.

31 China has closed some 50,000 MW of small coal plants in recent years; see *Power Magazine,* August 5, 2009.

Figure 7

U.S. Coal-Fired Power Plants as of December 31, 2008[32]



b. The Cost of Retrofits for Control of Criteria Pollutants

Criteria pollutants include specific emissions for which there are specific standards, including oxides of nitrogen, sulfur dioxide, plus toxic substances like mercury. Initially, these requests will likely include the cost of SO_2 scrubbers, SCR, and mercury controls. They will involve baghouses and fabric filters. These will be needed to continue operations once forthcoming regulations are implemented. Based on recent experience, these types of controls will likely cost $200 to $500 per kW of capacity—enough to double the current rate base associated with these older units.[33]

But these investments may be followed by requests to cover the costs of carbon regulation and other measures, such as cooling towers to address once-through cooling issues, and waste disposal equipment, transportation, and waste disposal sites to address coal combustion residual issues. Those costs may not be knowable and may be very high or quite moderate, depending on the timing and form of carbon regulation ultimately adopted.

Finally, all of these investments will involve operating expenses for staff, chemicals, and the power to operate the equipment. (See, for example, Fig. 9.) In many cases, the pollution control equipment will reduce the power output of the generating station (in some cases, plants may be upgraded to higher capacity during the retrofit shutdowns).

And finally, if carbon sequestration becomes the viable alternative that many fossil energy companies believe will occur, there will be additional capital costs, operating costs, and very significant energy costs to separate, transport, and sequester CO_2.

Figure 8 shows estimates for actual proposed retrofits for several Western U.S. coal plants for SO_2, NOx, and particulate emissions. These estimates range from $22/kW to $1,327/kW. The more expensive retrofits justify more comprehensive analysis beyond just the three pollutants being addressed. The figures below do not reflect the changes in operating costs or plant efficiency that are inevitable.

Figure 8 does not include any estimates for compliance costs associated with hazardous air pollutants (e.g.,

32 U.S. Energy Information Administration, 2008.

33 North American Electric Reliability Corporation, October 2010, pp. 50-55.

Figure 8

Cost Estimates for Proposed Pollution Retrofits on Selected Western Coal Plants[34]

Plant	MW	In-Service	Total $	SO_2 $/kW	NOx $/kW	PM10 $/kW	Total $/kW
Naughton	700	1963	$491,896,704	$304	$222	$177	$703
Boardman	617	1980	$470,800,000	$401	$362	—	$763
Johnston	330	1959	$438,000,000	$1,008	$77	$242	$1,327
Bridger	2,120	1974	$423,359,784	$21	$173	$6	$200
Big Stone	475	1975	$223,100,000	$297	$172	—	$470
Boswell	375	1958	$194,318,000	$211	$205	$102	$518
Wyodak	335	1978	$93,900,000	—	—	—	$280
Coal Creek	550	1979	$81,482,700	$139	$10	—	$148
Sherburne	1,373	1976	$30,600,000	$5	$17	—	$22

mercury), CO_2 or other climate change mitigation measures, ash management, or cooling. The total of these costs can easily be of the same magnitude or greater. Other estimates of retrofit costs have been published in reports previously cited in this paper.[35]

c. Emission Costs May Justify Permanent Closure of Some Plants

If all potential emission control and compliance costs are considered, it is likely that many power plants will be found uneconomical and closed permanently.

The key risk, however,

Figure 9

Illustrative Example of Potential Cumulative Retrofit Costs At A Single Plant

Cost Element	Year Incurred	Investment-Related Cost: Expressed as $/kW	Investment-Related Cost: Expressed as $/kWh	Operating Cost $/kWh	Cumulative Retrofit Cost $/kWh
Current Cost	2011	$200.00	$0.006	$0.030	$0.036
Selective Catalytic Reduction	2014	$200.00	$0.006	$0.005	$0.046
Low-NOx Burners	2014	$100.00	$0.003		$0.049
SO_2 Scrubbers	2016	$400.00	$0.011	$0.005	$0.066
Particulate Baghouse	2016	$100.00	$0.003	$0.001	$0.070
Cooling Tower	2018	$300.00	$0.009	$0.003	$0.081
Coal Residuals Disposal	2018			$0.003	$0.084
CO_2 Allowances @ $30/ton	2020			$0.030	$0.114

Note: Investment costs converted to $/kWh using a 15% fixed charge rate and 60% capacity factor.

34 National Park Service, 2010.

35 U.S. Energy Information Administration, 2008.

is that these expensive measures will come before regulators on a piecemeal basis, rather than in a comprehensive review. This can lead to more money spent over time than the final product is worth. Figure 9 shows an illustrative example of what might be spent for emission compliance on an older 300-MW coal-fired power plant; the costs are representative, but the in-service dates are entirely dependent on what is required and when, which is highly uncertain.

A power plant subject to all of these needed retrofits will be a more likely candidate for permanent shutdown and replacement with a newer low-emission generating unit, renewable energy resources, or energy efficiency investments. At some point during the gradual retrofit, the operating costs alone might make the plant uneconomical to run, independent of the investment costs required to keep it available for service; for example, rising coal commodity costs, due to increased exports to countries where coal displaces petroleum, are not even reflected in this illustrative example.

If all potential emission control and compliance costs are considered, it is likely that many power plants will be found uneconomical and closed permanently.

The key risk, however, is that these expensive measures will come before regulators on a piecemeal basis, rather than in a comprehensive review.

Many units have been scheduled for closure as a result of environmental compliance and other costs. Figure 10 is

Figure 10

Selected U.S. Coal Plants Closed or Scheduled To Close Due to Emissions Costs[36]

Plant Name	Principal Owner	Megawatts	Initial In-Service Date(s)	Shutdown Year	Principal Shutdown Cause(s)
Mohave	SCE	1,636	1971	2005	SO_2, CO_2, NOx, water, slurry pipeline
Boardman	PGE	601	1980	2020	SO_2, CO_2; may be repowered
Lee, Sutton, Cape Fear, Weatherspoon	Progress	1,500	1951, 1954, 1956, 1949	2013-2017	SO_2
Gorsuch	American Muni Power	200	1988	2011	SO_2, NOx
Wabash	Duke	350	1953	2010	SO_2, NOx
Arapahoe	Xcel	160	1951	2015	NOx, CO_2
Cameo	Xcel	66	1957	2010	CO_2
Cromby, Eddystone	Exelon	732	1954, 1960	2012/2013	Overall operating cost
Centralia	TransAlta	1360	1972	2020/2025	Legislatively negotiated

Abbreviations: *PGE, Portland General Electric; SCE, Southern California Edison.*

36 CoalSwarm, "Retrofit vs. Phase-Out of Coal-Fired Power Plants," 2011; Boardman data from Hirsh, Northwest Energy Coalition; In-service dates from U.S. Energy Information Administration, 2005 and 2008.

a partial list of units that have been closed or are scheduled to be closed (or re-powered) for various reasons.

d. Preapproval of Expenditures

Utilities often request preapproval of expenditures for pollution control equipment. Preapproval means that the regulator generally reviews the proposed investment and the associated budget and then, barring imprudence in implementing an approved plan, allows cost recovery. The concept of "prudence" can include such things as failure to consider factors known to management in the original proposal, failure to effectively manage the retrofit process, or failure to reconsider the project as additional cost information becomes available.

Preapproval is a common practice, and once obtained, cost recovery is highly likely. For example, under Ohio law, under an automatic recovery rider, utilities are able to recover the costs of environmental compliance, including "the cost of emission allowances; and the cost of federally mandated carbon or energy taxes…" and a "reasonable allowance for construction work in progress … for an environmental expenditure for any electric generating facility of the electric distribution utility…."[37]

Some state laws require a preapproval process, and some regulators have a policy of considering requests for preapproval without any legislative requirement. Others insist that investment decision-making is a management responsibility and will only review the actions of management when the investment is completed and enters service. Each regulator must make his or her judgment on this, guided by state law and regulatory precedent.

If preapproval is to be considered, regulators should insist on a clearly stated comprehensive plan for investment that can be reasonably anticipated given the state of the regulations, with some sensitivities, and a comprehensive analysis of project cost-effectiveness after the investment is completed so consumers are not signed up to pay for something that may not be completed or that may not work as expected once finished. Using the previous legislative example, a comprehensive analysis would evaluate the value of the project under a range of possible outcomes, including an explicit future price for carbon.[38] As discussed in what follows, such an analysis would include a consideration of future compliance costs and an evaluation of short-term and long-term alternatives to investment in an older power plant.

e. Requests for Adjustment Clauses

Some utilities have requested, and some regulators have granted, separate adjustment clauses for pollution control equipment costs. An adjustment clause (also sometimes referred to as a "cost tracker" or "tariff rider)" is a separate surcharge (or sur-credit) to track specific costs in rates, independent of the utility costs and rates established in a general rate case.[39]

One benefit of adjustment clauses is that the utility recovers dollar for dollar exactly the level of costs incurred. When rates are set in a general rate case, if sales volumes increase, the utility recovers additional revenues for which there may be no associated costs (and vice versa if sales decline). For example, retrofits of power plants often include modifications that increase the capacity of the units, meaning that more power can be produced from the modified plant and potentially sold on the market if the capacity is not needed for jurisdictional customers. In this case, there should be an offset for what customers pay for the upgrades or the customers should receive the value (minus an incentive payment) of the off-system sales to offset the cost of the pollution control upgrade.

One thing regulators will need to consider is whether emission management costs bring with them offsetting cost savings. For example, if scrubbers are installed at a coal plant to reduce sulfur emissions, the utility will avoid the need to buy SO_2 allowances. In addition, the utility may be able to operate the plant more of the time, avoiding purchasing or generating higher cost power from other sources. These issues can be considered in either a special purpose rate proceeding or a general rate proceeding.

37 Ohio Revised Code, Section 4928.143(B)(2)(a)and (b).

38 For the purpose of this discussion, a price for carbon could come in the form of a carbon tax, a cap-and-trade mechanism, or an offset requirement; the issue is that some future price for carbon emissions would be evaluated.

39 For a general discussion of adjustment mechanisms, see Lazar, Regulatory Assistance Project, March 2011.

According to the National Regulatory Research Institute (NRRI), regulators have traditionally approved adjustment clauses under "extraordinary circumstances," characterized as (a) unpredictable and volatile, (b) largely outside the utility's control, and (c) involving costs that are substantial and recurring.[40] Also, historically, in order to get cost recovery through this mechanism, "regulators required that all three conditions exist…." [41] According to NRRI, their popularity "reflects the perception that these mechanisms are necessary to prevent a utility from earning a rate of return substantially below what was authorized." [42]

Regulators have traditionally approved adjustment clauses under "extraordinary circumstances," characterized as (a) unpredictable and volatile, (b) largely outside the utility's control, and (c) involving costs that are substantial and recurring.

In general, emission management costs are not volatile; they involve large capital investments and predictable periodic operating costs. But they do meet the other two criteria: outside the utility's control, and substantial and recurring.

Regulators should consider whether or not one-time environmental compliance costs meet the criteria for cost-trackers, and if this or another approach better guarantees that company management, as it develops environmental compliance strategies, will make least-cost choices. Because they provide for the automatic inclusion of pre-defined costs in rates, cost-trackers largely take away a utility company's incentive to minimize costs. Cost-tracker mechanisms typically come with the opportunity for an after-the-fact prudence review, but they place the burden of demonstrating imprudence on the public advocate or other stakeholders.

Denials of cost recovery in this context could also appear inequitable by comparison to a more traditional regulatory approach that makes company management responsible for demonstrating, in the first place, the reasonableness of its decisions and related costs before they are put into rates. Also, with the high cost of pollution control, utilities seek to minimize their risk by transferring more and more costs to consumers. Furthermore, this issue of raising capital becomes more contentious when dealing with multi-state utilities in which individual utilities compete with their affiliates for parent company funds.

40 Costello, 2009.

41 Costello, 2009.

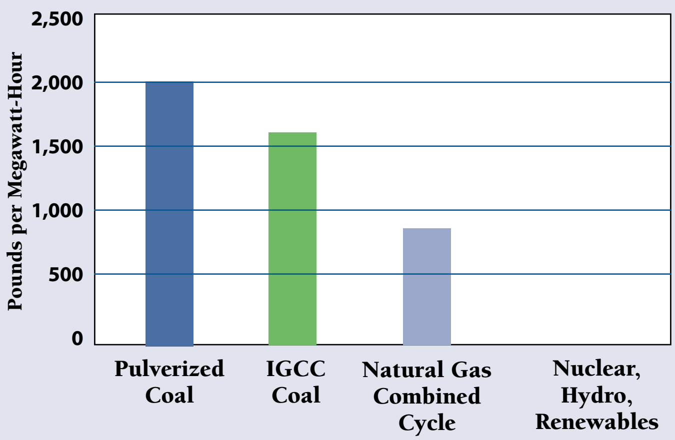
42 Costello, 2009.

4. Costs of CO_2 Reduction or Mitigation

The biggest wildcard in the future of coal- and fossil fuel-fired electricity generation is the potential cost of reducing or mitigating emissions of CO_2. Coal combustion results in the highest level of CO_2 emissions per unit of electricity of any major resource. Figure 11 compares CO_2 emissions from various electric generation technologies.

Figure 11

Approximate CO_2 Emissions of Electricity Generation[43]



Abbreviations: *IGCC, integrated gasification combined cycle.*

Currently there is no commercialized and cost-effective means of removing carbon from electric generator emissions as there is for other pollutants. Carbon capture and storage (CCS) is one of the CO_2 compliance strategies that industry has started to explore. According to the U.S. Department of Energy (DOE), "capture technologies available today are not cost-effective when considered in the context of sequestering CO_2 from power plants."[44] There are a number of reasons for this.

Before CO_2 can be collected and sequestered from sources like power plants, it has to be captured as a relatively pure gas. This is a challenge because power plants use air-fired combustors, a process that exhausts CO_2 diluted with nitrogen (typically 10-12% CO_2 by volume for coal plants) and requires that the gas be separated and concentrated.[45]

In pilot programs, CO_2 is currently recovered from combustion exhaust by using amine (derivatives of ammonia) absorbers and cryogenic coolers. The cost of CO_2 capture using this approach, however, is on the order of $150 per ton of carbon, which could increase the cost of electricity by 2.5 to 4 cents/kWh, depending on the exact type of process used. This is a significant increase over the U.S. average retail price of electricity, which was 9.87 cents in May 2011.[46]

Furthermore, the "capture" of CO_2 from combustion exhaust is only one part of CCS. There are also significant costs associated with the development of CO_2 storage, transport, and sequestration options. Technical innovation could dramatically change these estimates in the future.[47]

Although the EPA is expected to issue New Source Performance Standards for GHGs in the fall of 2011, it is not clear what form they will take. According to some commentators, the EPA has a significant degree of flexibility in setting them:

> *Given agency discretion to define uncertain statutory terms like "best system of emission reduction," and given*

43 Regulatory Assistance Project calculation based on Synapse Energy Economics, 2006, Chapter ES; only generation-related emissions are reflected, not construction or fuel-production emissions.

44 U.S. Department of Energy, "Carbon Capture Research," 2011.

45 U.S. Energy Information Administration, 2011.

46 U.S. Energy Information Administration, 2011.

47 It should be noted that the U.S. Department of Energy has been supporting pilot CCS projects and regional partnerships around the country; see U.S. Department of Energy, "Carbon Sequestration Regional Partnerships," 2011; see also Wood, 2011.

> *the potential of compliance flexibility mechanisms to reduce costs while preserving total emissions reduction goals, EPA and the states should be able to fit a variety of flexible approaches into the statutory criteria for performance standards.*[48]

If the EPA is able to grant compliance flexibility to states, this could pave the way for the use of market-based compliance approaches, potentially lower-cost alternatives to CCS or related control technology approaches that are still at a research, development, and demonstration level. Existing market-based compliance approaches include: (1) the 3-year-old Regional Greenhouse Gas Initiative, in which 10 northeastern states implemented a cap-and-trade program for electric generation; (2) the EU Emissions Trading Scheme (ETS),[49] started in 2005; (3) California's greenhouse gas program,[50] slated for a January 2012 start; and (4) the federal CAA's 20-year-old acid rain program.

Although the political debate between command-and-control and other market-based approaches is beyond the scope of this paper, one day carbon emissions are likely to carry a cost. Regulators need to be prepared to recognize this, quantify its attendant risks, and include it in their analyses of proposals for cost recovery of environmental compliance costs.

Market-based compliance mechanisms would allow those better situated economically to make the decision to invest in compliance technology to reduce emissions and then sell/trade any extra emissions reductions (allowances) to other affected sources for which investment in technology would be a more expensive option. Note also that other countries and jurisdictions, including China, New Zealand, and Tokyo, Japan are considering these issues and adopting or piloting similar programs.[51]

Although the political debate between command-and-control and other market-based approaches is beyond the scope of this paper, one day carbon emissions are likely to carry a cost. Regulators need to be prepared to recognize this, quantify its attendant risks, and include it in their analyses of proposals for cost recovery of environmental compliance costs.

48 See for example, Wannier et al, 2011, p. 1; and Litz et al, 2011.

49 See European Commission, 2011. Europe's carbon market or "Emission Trading Scheme." http://ec.europa.eu/clima/policies/ets/index_en.htm

50 In 2006, California adopted "the Global Warming Solutions Act of 2006," which establishes various programs, including a market-based program to reduce greenhouse gases that is supposed to start in January 2012; see California Environmental Protection Agency, 2011.

51 China's national energy regulator, the National Development Reform Commission, is in the process of developing cap-and-trade pilot programs in regions like Heilongjiang, Liaoning, Guangdong, and Hubei, and municipalities like Beijing, Tianjin, Shanghai, and Chongqing. See also New Zealand Ministry for the Environment, 2011; Tokyo Metropolitan Government, Bureau of the Environment, 2010; and Nishida, 2011.

5. What Should Regulators Require of Utilities?

The role of utility regulators is to provide a framework in which utilities recover prudently incurred costs associated with provision of service to consumers, while ensuring that consumers do not pay either inappropriate costs or provide excessive profits to utilities. In addition, regulators have the responsibility to allocate these costs fairly among customer classes and to design rates that are fair, just, and reasonable.

This section addresses the information that regulators should expect utilities seeking approval for retrofit investments to provide. It also addresses the risks that utilities should bear as part of the process of plant refurbishment, and what consumers should expect as a final result.

Should Utility Regulators Oppose Implementation of New Health and Environmental Regulations on Power Plants?

Regulators may be asked by non-regulated generators to help oppose implementation of health and environmental regulations, on the basis that these regulations will increase market prices for power, and thus drive up wholesale and retail power rates. This is clearly a political role, and regulators will need to determine if participation in this type of issue is appropriate under the circumstances of their office. However, there are some important economic factors. To the extent that new gas-fired generation or renewable energy resources are available at lower costs than the sum of existing costs for older power plants plus the cost of needed upgrades, those resources will be competitive, and the owner of existing generation will be limited in how much they can charge. To the extent that energy efficiency resources are available at lower costs, an aggressive energy efficiency program may put downward pressure on the entire supply curve of competing generation, bringing huge offsetting economic benefits to consumers.

Regulators should establish clear requirements for utilities seeking cost recovery for investments in older power plants. The most important requirement is that a comprehensive analysis be prepared, considering all pending and potential investments that may be required to allow the unit to operate into the future. Regulators need all the facts or best available information and opinions at the time the utility asks for something, and should not accept only part of the story when rendering such momentous decisions.

At a minimum, the analysis should include the elements in the following checklist at the time regulators review any request for cost recovery for any emissions controls for an existing power plant:

- Operating history for the power plant and associated cost data
- Remaining life of major components of the power plant
- Status of compliance with existing public health and environmental regulations
- Cost of retrofits required in the short run to continue operations in compliance with existing regulations
- Cost of potential retrofits or other strategies required in the long run to continue operations, given forthcoming state environmental regulations
- Cost of potential retrofits or other strategies required in the long run to continue operations, given forthcoming EPA rules
- Range of estimates of potential CO_2 regulation costs
- Available alternative conventional generation resources
- Available alternative renewable generation resources
- Available energy efficiency resources in the utility service territory
- Available demand response (peak load management)

resources in the utility service territory
- Available distributed generation resources, including combined heat and power, wind energy, and customer-sited solar
- Available transmission and distribution system efficiency improvements
- Potential new transmission connections to available cleaner resources outside the utility service territory
- A life-cycle cost analysis comparing plant refurbishment and operation to the least cost alternative mix of supply and demand resources available if refurbishment is not pursued
- Evaluation of options within a portfolio of power plants to concentrate retrofits on larger, newer plants for which the per-kWh retrofit costs are reasonable, and continue to operate older, smaller, dirtier plants on an as-needed basis, provided the total emissions meet overall emission goals

The required analysis and data should accompany the request for consideration of compliance cost recovery.

For many utilities, the proper way to prepare such an analysis is in the context of an IRP, portfolio management, or some other planning process. IRPs consider all available options to meet future requirements and compare them, considering cost, risk, reliability and other factors. The value of an IRP in this context is that all future potential costs and risks for a retrofit project are considered over the remaining lifetime of the resource and compared to alternatives.

Some utilities obtain much or all of their power from a wholesale supplier or suppliers, which may limit their contractual ability to substitute resources. Others operate in restructured states, and their power supplies are unregulated while their distribution service is subject to state regulation. This paper is primarily directed at the role of state utility regulators with respect to traditional, vertically-integrated utilities that own (or have long-term contracts for) generating facilities in addition to their distribution facilities.

In June 2011, in an investigation by the Oklahoma Corporation Commission (OCC) on the potential effects on Oklahoma of existing and forthcoming federal environmental regulations,[52] one environmental group proposed that the OCC adopt "Integrated Environmental-Compliance Planning." It is an approach that, in many ways, works like an IRP.[53] It considers supply-side, demand-side, and delivery options in an integrated manner. It focuses, however, more closely on the requirements of forthcoming public health and environmental regulations. These concerns include emissions of CO_2, SO_2, NOx, mercury and other hazardous pollutants, coal combustion wastes, and limiting the amount of water necessary to cool thermal electric generating plants. Whether a commission employs integrated resource planning or integrated environmental-compliance planning, reviewing investments in an "integrated" manner is the key:

> *Responding to these requirements piecemeal will result in inefficient and unnecessarily expensive decisions. The sheer number and wide coverage of these pending rules mandates that the Commission and the utilities consider their potential impact in a comprehensive, rather than case-by-case basis, for both planning and cost recovery. The Commission should expect to see the anticipated costs and the potential risks of existing and emerging regulations for the whole range of pollutants in utility evaluations of their investment proposals. Given the capital-intensive and long-lived nature of investments in the electric industry, if the final form or timing of a regulation is unknown, the analysis should include both an expected value of the cost of compliance and the range of plausible costs.*[54]

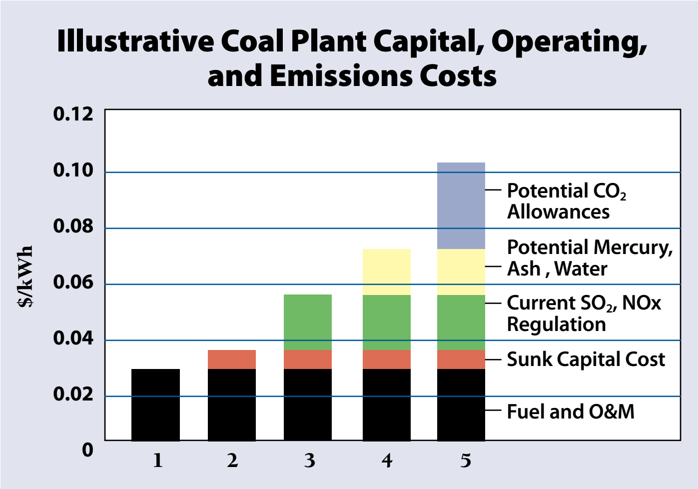
Figure 12 emphasizes the importance of planning by looking ahead to all likely environmental costs that may be candidates for inclusion in utility rates. It compares, in a simple illustrative way, the cost of power from an existing

52 Oklahoma Corporation Commission, 2011.

53 Colorado's "Clean Air – Clean Jobs Act" (HB 10-1365) is another example of Integrated Environmental-Compliance Planning. The Act anticipates new EPA regulations for NOx, SO_2, and particulates, mercury, and CO_2. It requires Colorado's two investor-owned utilities to consult with the Colorado Department of Public Health and Environment on utility plans to meet current and "reasonably foreseeable EPA clean air rules," and to submit a coordinated multi-pollutant plan to the state Public Utilities Commission; see Colorado Legislative Council, 2011.

54 Sierra Club, July 18, 2011, p. 5.

Figure 12



coal plant without retrofit, with two levels of retrofit and with carbon costs. The first bar shows only the operating costs of the plant under existing regulations. The second bar adds the capital recovery of the remaining investment in the plant; most utilities and some regulators would consider these "sunk" costs and not a part of a forward-looking economic analysis. The third bar adds a rough amount for the costs of meeting current SO_2 and NOx emissions regulations. The fourth bar adds a rough amount for the costs of meeting potential mercury, ash, and water regulations. The last bar adds a rough amount for the costs of meeting potential CO_2 regulations. The point of this *illustrative* example is not to assign specific values to each element but to indicate the rough order of magnitude of these costs.

The "fully renovated" power plant in this illustrative example would have costs of about $0.11/kWh, compared with $0.03/kWh for the current operating costs and $0.036 for the current fully allocated costs, including a return on the existing investment. This renovated cost is well above the estimated cost of energy efficiency, wind, and geothermal generation and approaching the cost of solar and nuclear generation. The regulator would clearly want to consider whether it is cost-effective to consider plant renovation, given the future exposure that is evident.[55]

a. Utility at Risk for Elements Not Evaluated

The utility will be motivated to do a comprehensive analysis if it understands that the shareholders, not the ratepayers, will be at risk for any costs that are not considered when the first request for consideration of pollution control costs is filed. There is no reason the utility should have any greater assurance of cost recovery for these types of costs than for any other investment it makes, particularly if they cannot demonstrate having examined available alternatives over the life cycle of the proposed investment.

These are not impositions "beyond the control" of the utilities; the utilities are firmly in control of the decision of whether to renovate or whether to choose alternatives. Utilities are required to follow many other requirements, from local government land use regulation to industry-imposed safety and reliability standards. Environmental and public health regulations are just a part of the mix of regulations that utilities deal with as a part of their ordinary business risk—they also face labor, workplace safety, land-use, and other regulations imposed by local, state, and federal agencies.

For example, if the utility prepares a partial analysis considering only NOx and SO_2 costs but not costs such as combustion residuals management or CO_2, then the regulator should make it clear that the utility is at risk for future incremental costs that were not considered.

This is most important to prevent piecemeal evaluation. The utility may fear that presenting a complete picture may lead to the regulator rejecting a request for cost recovery of retrofit costs. That rejection could leave the utility with a non-operable plant, and recovery of the remaining investment may be at risk (see an extended discussion of this topic later in this paper).

The role of the regulator is to apply reason and judgment to any decision. For example, if the utility considers all known and probable retrofit requirements and concludes that it is cost-effective to modify a plant for continued operation, and additional unanticipated regulations are

55 For more information on planning, see Moskovitz, 1989; for a discussion of the Colorado Clean Air – Clean Jobs Act, see Farnsworth, 2011, p. 21.

imposed later, the regulator could consider an additional cost recovery request. Regulation is not a static science.

The point of all of this is that the regulator must require the utility to do a thorough, objective, and transparent analysis of potential costs, and put that analysis to public scrutiny through the IRP process or an issue-specific proceeding.[56] If it is cost-effective to improve and operate the power plant, the regulator should have the information to make that judgment. If it is not cost-effective, the regulator should have that information so that a reasoned judgment can be made on the disposition of the retrofit project. And if something is left out of the analysis, the utility should be at risk for the costs not considered.

The prudence standard as imposed by most regulators considers what the utility knew or could have known at the time of a decision. In the 1980s, when high-cost coal and nuclear plants were coming into service and electric rates were rising sharply, nearly every regulatory commission considered the prudence of these investments based on what was known and measurable at the time. Many regulators disallowed portions of the costs of both completed projects and abandoned projects. The potential retrofit costs and incremental operating costs for existing power plants are as large as or larger than the costs of new resources added in past decades.

b. Examination of Non-Generation Alternatives

Integrated resource planning compares power plants to non-generation alternatives such as demand response and energy efficiency. In states without IRP or other related processes for consideration of these alternatives, a process to compare coal plant retrofits with non-generation alternatives may not be well developed.

Demand Response: If the generating units being considered for retrofit are needed only to meet peak demand for a few days or weeks of the year, then demand response programs may be able to replace the units. “Demand response” is a term used to describe programs to change patterns of electric consumption in response to 1) changes in the price of electricity, or 2) incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[57]

Distributed Generation: New small generating resources located at customer facilities permit the utility to avoid not only generation costs, but also costs associated with transmission, distribution, line losses, and reserves. A full analysis of potential combined heat and power potential, customer-site solar, small wind generation, and other local generation is needed to fully examine distribution generation options.

Energy Efficiency: Improving the efficiency of energy end-use reduces total kWh consumption as well as peak demand. In most cases, the impact on peak demand is even greater than the average impact, simply because most energy-using devices (e.g., air conditioners) have usage concentrated in the on-peak period. Energy efficiency therefore can help displace the need to renovate older power plants regardless of whether these units are needed only during peak periods or if they operate as intermediate or baseload generating units.[58]

Renewable Energy Resources: Full consideration needs to be given to renewable energy alternatives available at the utility level, including wind, solar, geothermal, hydro, wave and current energy, and other options, plus energy storage options, such as pumped storage, that can convert as-available generation into firm capacity.

Natural Gas Generation: New natural gas generation is a common choice for utilities and non-utility generators to meet customer demand. Modern natural gas generators with state-of-the-art emission controls have extremely low

56 For example, the Oregon Public Utilities Commission created an issue-specific docket for consideration of the Best Available Retrofit Technology analysis for the Boardman power plant, and then folded that analysis into the Portland General Electric IRP process. Both parts had transparency and public participation.

57 Federal Energy Regulatory Commission, 2011.

58 In evaluating the contribution of energy efficiency, it is crucial to consider the marginal line losses and marginal impact on generation reserves. A discussion of these topics is presented in Lazar and Baldwin, 2011.

emissions of criteria pollutants and less than half the CO_2 emissions per unit of output compared with coal units. Use of natural gas in existing coal boilers may be an option if carbon capture and sequestration is anticipated to be available within a reasonable period of time.

Knowing the hourly load shapes is important to evaluating non-generation alternatives when considering renovation of older power plants for meeting peak demand. Groups in New England and the Pacific Northwest have done extensive end-use load analysis to examine the shape of hundreds of end-uses for electricity. This information informs the analysis as to what alternatives will best meet customer demands and what savings can be achieved through energy efficiency, allowing more accurate analysis of the relative value of alternatives to retrofitting any particular power plant.[59]

c. Time Horizon for Analysis

The time horizon for comparison between the renovation of an older power plant and available alternatives should extend at least to the end of the lifetime of the renovated plant. For example, if renovation to address emissions would allow the plant to be operated for another 20 years, then the evaluation should encompass at least this life cycle.

Because replacement resources, including both generation and non-generation options, may have a shorter or longer lifetime than the renovated plant, it is important that the analysis be prepared on a levelized unit-cost basis. Use of this approach allows for the reasoned ("apples to apples") comparison of measures with different lifetimes. Figure 13 compares on an illustrative basis two generation options with long lifetimes to several energy-efficiency measures with shorter lifetimes. The actual costs for each of these options would be technology-, situation-, and region-specific.

The utility would be expected to implement all available measures costing less than coal plant renovation prior to consideration of that renovation. Without any CO_2 costs, coal would clearly be cheaper than natural gas. If the regulator determined that CO_2 costs were likely to be incurred at a level of $30/ton, then the entire list of alternatives would be less expensive than renovation of the coal unit. A properly completed IRP will detail the available supply of energy efficiency and the achievable implementation schedule, allowing a determination of the adequacy of energy efficiency to displace existing (or new) supply-side resources.

Figure 13

Illustrative Measure Lifetimes and Levelized Costs [60]

For Various Coal, Natural Gas, and Energy Efficiency Resource Options

Measure *(illustrative only; no specific cost data used)*	**Measure Lifetime**	**Levelized Cost $/MWh**
Coal plant renovation w/o CO_2	20	$50
Coal plant renovation w/ CO_2 @ $30/ton	20	$80
New gas combined cycle w/o CO_2	25	$60
New gas combined cycle w/ CO_2 @ $30/ton	25	$75
Residential weatherization retrofit	30	$55
Residential new construction code upgrade	50	$20
Commercial lighting retrofit	12	$25
Industrial motor upgrade	15	$10

59 For more information on evaluation of energy efficiency as an alternative to generation, see Northwest Power and Conservation Council, 2010, Chapter 4.

60 These are not actual costs for any specific analyzed resource; they are roughly accurate and intended to be illustrative of the concept that CO_2 costs can push coal plant retrofit expense above the cost of alternatives.

d. Example Analyses That Considered Only Immediate Costs

Minnesota: Boswell

The Boswell 3 power station is a 375-MW coal-fired generating unit that began operation in 1973.[61] In 2006, Minnesota Power, the operator, requested that the Minnesota PUC consider and approve the estimated costs of $198 million, or over $500/kW. The retrofits are designed to reduce 81% of NOx emissions, 90% of SO_2 emissions, 93% of particulates, and up to 90% of mercury emissions.[62]

Minnesota Power applied to the Minnesota PUC for approval of the "Boswell 3 Plan" to bring this plant into compliance with state regulations, and requested an associated tariff rider for cost recovery. The plan set forth the proposed retrofit elements and associated costs. Included in this was the cost of upgrading the plant turbine to increase its generating capacity, replacing that which would be lost due to the energy use of the pollution control equipment.

The Minnesota PUC approved the Boswell 3 Plan, including a tariff rider that provides for full recovery. The increased capital and operating costs thus were recovered outside of a general rate case. The decision did not include any analysis of the potential cost of forthcoming environmental mitigation measures: the EPA's Mercury/Air Toxics rule, New Source Performance Standards for CO_2, or other pending EPA rulemakings, some of which may be more stringent than the Minnesota state regulation. It did not inventory available energy efficiency, renewable energy, or demand-response resources. It is unknown whether an alternative path may have been lower cost for electric consumers in the long run.

This is an example of incremental approval of very large expenditures without a complete picture of the potential future costs associated with continued operation of an aged power plant.

Entergy: White Bluff, Arkansas

White Bluff is a two-unit, 1,700-MW power plant near Redfield, Arkansas built in 1980. The owner, Entergy, proposed an expenditure of $1.04 billion for reduction of SO_2 and NOx emissions. White Bluff is one of the 25 largest mercury emitters in the United States.[63] Critics, including the Sierra Club Arkansas chapter, have requested that the Arkansas Public Service Commission evaluate White Bluff on a comprehensive basis, looking at SO_2, NOx, mercury, and CO_2 compliance costs together.[64] They contend that if all of the potential costs are considered, plant retirement is the cost-effective option.[65]

e. Example Analyses That Consider Future Potential Costs

There have been several analyses of coal plant renovation costs that follow the criteria discussed previously: full consideration of certain, probable, and potential compliance costs. In some cases, these have also examined the public health and environmental costs of the residual environmental impacts. Some have fully considered potential CO_2 costs. The following three examples illustrate some of the more complete analyses.

Ontario

In April 2005, the Ontario Ministry of Energy released a report on Ontario's coal-fired generation.[66] This study examined the potential cost of operating existing coal plants under the then-current regulatory scheme, renovating the plants, or replacing the units with either natural gas or nuclear generation. In each case, both the direct economic costs and the externalized public health costs associated with electricity generation were considered, although the analysis did not consider non-generation alternatives.

The final result of this study is shown in Figure 14. All alternatives were compared on a life-cycle cost basis.

61 CoalSwarm, "Boswell Energy Center," 2011.

62 Minnesota Power, 2011.

63 Environmental Defense Fund, 2011.

64 Beyond Coal Arkansas, 2011.

65 Mother Nature Network, 2009.

66 DSS Management Consultants, 2005. DSS Management Consultants, 2005.

Figure 14

Costs for Operating, Renovating, or Replacing Ontario's Coal Plants[67]

	Scenario			
	1 Base Case	**2 All Gas**	**3 Nuclear/ Gas**	**4 Stringent Controls**
Total Present Value (2007-2026) ($Billions)	**$49** ($21)*	**$29** ($26)	**$22** ($18)	**$32** ($21)
Annualized Costs ($Millions)	**$4,377** ($1,836)	**$2,605** ($2,279)	**$1,942** ($1,635)	**$2,802** ($1,895)
Levelized Costs ($/MWh)	**$164** ($69)	**$98** ($86)	**$72** ($61)	$105 ($71)
Health and Environmental Proportion	77% (46%)	**20%** (9%)	**21%** (6%)	**51%** (28%)

**Note: Values shown in parentheses are based on acute premature mortality damage estimates.*

The most expensive option (the Base Case) was continued operation of the units without environmental controls, because of the public health impacts of unimproved operation. The total public health and environmental impacts associated with unimproved coal plant operation were estimated at $0.137/kWh—more than the total retail cost of electricity.

California: Mohave

The Mohave generating station, a 1,580-MW pulverized coal unit built in 1970, was in need of major renovation. In December 1999, a consent decree was reached with the Grand Canyon Trust and other groups that required installation of SO_2 scrubbers by December 31, 2005, but the plant also needed refurbishment of other components. The estimated cost of renovation was $1.2 billion. The California PUC ordered a complete analysis of alternative and complementary options for Mohave.[68]

The Mohave Generating Station Alternatives/ Complements Study compared both supply-side and demand-side options.[69] It analyzed available renewable energy resources and the transmission capacity required to bring them to market.

Energy efficiency alternatives were not a part of the MACS report, because California already required utilities to acquire all cost-effective energy efficiency resources by the time the study was initiated.

The study itself did not recommend renovation or abandonment. Upon release, however, the project owners, led by Southern California Edison (SCE), elected to close the unit permanently.[70] A federal review of this decision states:

Ultimately, it was a business decision that led to the closure of the Mohave Generation Station. From the perspective of the plant owners, the significant expenses related to the installation of pollution abatement equipment along with issues related to fuel supply outweighed the incremental costs of finding alternative sources of power. The Mohave Generation Station was closed due to concerns about the high levels of SO_2, NOx, and particulate matter resulting from plant operations, a situation common to many of the Nation's older coal-fired plants.[71]

Oregon: Boardman

The Boardman unit, built in 1980, is a 601-MW pulverized coal generating station located in eastern Oregon. It is jointly owned by PGE and several minority partners.

The unit was built without scrubbers and was subject to review due to regional haze issues. As a part of the Best Available Retrofit Technology (BART) review, PGE examined three alternatives, each of which involved increasing costs, coupled with a longer plant operating lifetime. PGE ultimately proposed to discontinue coal use at the plant in the year 2020, rather than invest significantly more in renovation to

67 DSS Management Consultants, 2005.

68 California PUC, 2004.

69 Synapse Energy Economics, 2006.

70 Southern California Edison, 2011.

71 U.S. Energy Information Administration, "Southwest Weathers Closure of Mohave Generation Station."

Figure 15

Options Considered for Continuing Operation of Boardman Coal Plant [73]

	2011 NOx	2014 SO_2	2017 NOx	Closure Date
Existing Rules	NLNB/MOFA	SD Scrubber	SCR	2040+
DEQ Option 1	NLNB/MOFA/SNCR	SD Scrubber	—	2020
DEQ Option 2	NLNB/MOFA/SNCR	DSI	—	2018
DEQ Option 3	NLNB/MOFA	—	—	5 years after SIP approval (2016?)

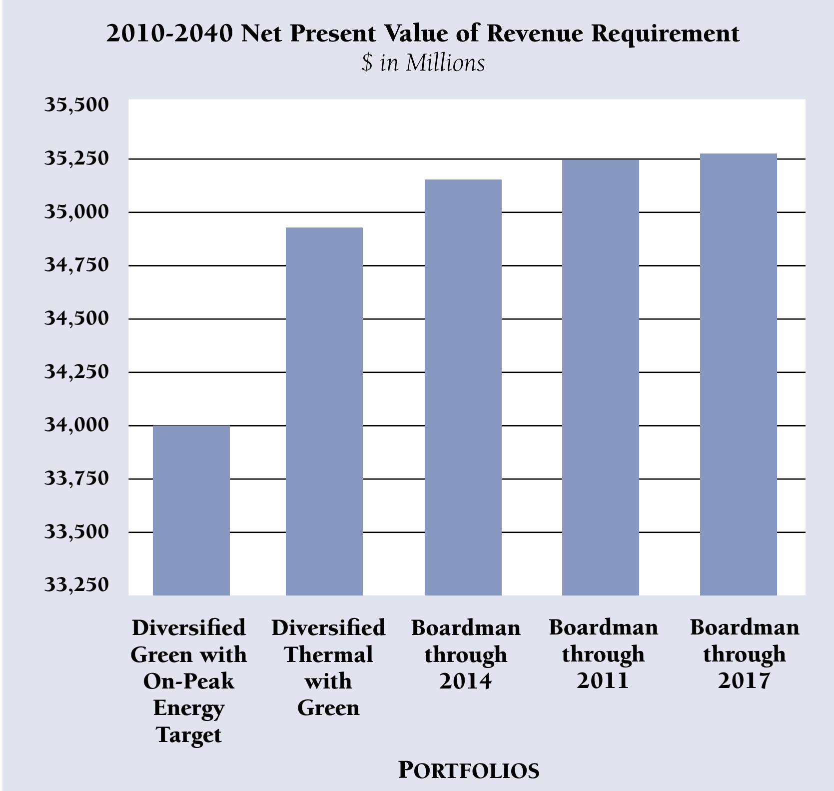
Abbreviations: BART, Best Available Retrofit Technology; DEQ, Department of Environmental Quality; DSI, Dry Sorbent Injection; NLNB/MOFA, New Low NOx Burners with Modified Overfire Air; NLNB/MOFA/SNCR, New Low NOx Burners with Modified Overfire Air and Selective Non-Catalytic Reduction; SD, Semi-Dry; SCR, Selective Catalytic Reduction; SIP, State Implementation Plan.

continue operations to 2040.[72] Figure 15 shows the options that were evaluated, showing additional measures required to continue operation further into the future.

The Boardman study itself did not consider alternative generation or non-generation options. The evaluation of Boardman was folded into PGE's overall IRP update, however, which did consider alternatives to Boardman. The IRP analysis included CO_2 costs in a range of $12 to $65/ton. The IRP concluded that the value of Boardman was limited and that early termination actually carried a lower present value of revenue requirements for the utility consumers, as shown in Figure 16 from the PGE IRP.[74] On the basis of its IRP analysis, PGE ultimately proposed termination of coal use at Boardman at the earliest date that the utility felt resulted in adequate reliability for its customers: 2020. The Oregon PUC acknowledged this approach in its order on PGE's IRP.[75]

Figure 16

Costs Associated with Alternative Options for Continued Operation of Boardman Coal Plant [76]



72 Portland General Electric Company, 2010.

73 Portland General Electric Company, 2010.

74 Portland General Electric Company, 2009.

75 Oregon Public Utility Commission, 2010, pp. 7-17. IRP acknowledgment does not guarantee favorable ratemaking treatment; it means the plan seems reasonable at the time acknowledgment is given; see Oregon Public Utility Commission, 2007, pp. 2, 24-25.

76 Black and Veatch, 2010.

Colorado: Cherokee

Xcel Energy (Public Service Company of Colorado) decided to retire the Cherokee generating station, a four-unit coal plant located in the Denver Metropolitan area. The decision process, and economic logic, is an excellent example of a utility looking ahead and making a decision based on current and anticipated emission regulations and availability of alternative generation and energy efficiency resources.

The Cherokee units were built in 1957 to 1968. Retiring the two oldest and smallest units was a relatively easy decision, as they were comparatively uneconomical even before considering retrofit costs. Cherokee 3 and 4 had more promising economics, as they are newer and larger (151 MW and 351 MW, respectively).

The Colorado Clean Air – Clean Jobs Act of 2010 provided a roadmap for coal plant refurbishment and retirement.[77]

Under the directive of this Act, Xcel examined the retrofit costs for SCR for NOx control, Lime Spray Dryers for SO_2 control, and ACI for mercury control. The total estimated retrofit costs were $762 million—about $1,500 per kW. The estimated cost of a replacement combined-cycle generating unit was $900 to $1,200 per kW, but the expected fuel costs were higher.

The estimated savings of $148 million, present value, were clearly dependent upon the estimated future additional cost of carbon regulation for a coal plant, compared with a natural gas unit (see Figure 17). This included an assumption that Xcel would be allowed to recover the undepreciated remaining rate base in the Cherokee units.[78]

Figure 17

Xcel Energy's Economic Analysis for Cherokee Plants [79]

	Refurbish	Retire
SCRs	$316	
Other Refurbishment	$446	
Replacement Capacity		$246
Fuel	$709	$1,300
CO_2 (Cherokee Excess)	$264	
Accelerated Depreciation		$41
Total Cost	**$1,735**	**$1,587**
Savings from Retirement		**$148**

Xcel then examined an alternative in which more aggressive energy efficiency was used to delay (but not eliminate) the need for replacement capacity. In this scenario, a savings of $204 million was estimated.

Xcel made the decision to retire Cherokee, accelerate its energy efficiency program, and consider replacement capacity.[80] The Colorado PUC approved the plan on December 9, 2010.

77 Colorado General Assembly, 2010.

78 Wishart, 2011.

79 Wishart, 2011.

80 See, e.g., Edison Electric Institute, 2011.

6. Cost Recovery For Refurbishment or Abandonment

Utility regulators must consider whether the cost of all utility investments, including pollution control measures, will be recoverable in rates from electric consumers. Depending on state policies, these reviews take place before, and in some cases after, the expenditures are made. In either case, however, the role of the regulator is always to determine if the utility's course of action is prudent, considering cost-effectiveness, reliability and availability of alternatives. In some states, regulators are limited in their authority to allow cost recovery for abandoned projects, but in most states the law allows regulators flexibility to act with a broad definition of the "public interest."

The role of the regulator is always to determine if the utility's course of action is prudent, considering cost-effectiveness, reliability and availability of alternatives.

Prudence is a multi-faceted measurement, ultimately determining if the utility did the right thing under the circumstances, as they could reasonably be understood at the time. The need to consider carbon management costs is increasingly evident in the industry and in the marketplace.

Here we discuss some of the methodologies used by regulators to make pre- and post-expenditure determinations of prudence, and provide several examples of regulatory disallowance of costs where the utility's expenditure was determined inappropriate for recovery.

To date there have been few if any disallowances of pollution control equipment costs after they were incurred. The magnitude of these costs and the range of possible solutions, coupled with the uncertainty of future regulations, however, increases the likelihood of challenges in the future. In their role to regulate in the public interest, utility regulators must look beyond any frustration with federally imposed regulations to the fundamental question of what is the best path forward to meet local energy needs at the lowest total combined cost, including direct costs, indirect costs, and a reasonable assessment of prospective costs.

a. Planning-Stage Consideration of Renovation Costs

The Boswell 3 discussion earlier in this paper is an example of planning-stage consideration and *preapproval* of renovation costs. At the same time it considered approval of the expenditures for plant renovation, the Minnesota PUC approved the cost recovery mechanism for the costs and the rate design through which the costs would be recovered.

The Mohave and Boardman examples are instances of planning-stage consideration of renovation costs by regulatory bodies, but not the cost recovery mechanism or rate design. In the case of Mohave, no costs were incurred after the study for renovation, but the cost of replacement resources will be examined in appropriate regulatory proceedings. In the case of Boardman, some costs are being incurred for interim improvements, but the Oregon PUC has not yet approved the inclusion of these costs in rates. The Mohave and Boardman examples do not constitute instances of "preapproval" of expenditures.

In the case of Mohave, the owner, SCE, originally requested an accounting order to defer preliminary retrofit-related engineering costs. The California PUC ordered a complete analysis of SCE's proposal. As a result of the analysis and SCE's determination that proceeding with retrofit was not economical, SCE determined not to make the investment.[81] In the case of Boardman, PGE examined alternatives and submitted its analysis to the Commission for review as part of an integrated resource planning process, ultimately agreeing to end coal combustion at Boardman by the year 2020.

81 The California PUC is now faced with two related decisions: the treatment of the abandoned project costs and the disposition of allowance values for SO2 credits no longer needed by the utility.

b. Evaluation-Stage Consideration of Renovation Costs

Many regulatory bodies will not consider preapproval of expenditures, instead reserving judgment until projects are completed and proposed for addition to the utility rate base in a general rate case or single-issue proceeding. Their logic is that it is the responsibility of management to make prudent decisions and to manage projects efficiently, whereas the role of the regulator is to pass judgment once management's decisions are complete.

The costs associated with power plant renovation are so large that nearly all utilities will seek some sort of pre-determination of the acceptability of their project plans. Even when plans are "accepted" or "approved" by the Commission, however, there is still a need to review whether the ensuing expenditures were prudently managed.

The Kettle Falls generating station is a 60-MW wood-waste-fired plant in northeast Washington State owned by Avista Utilities (formerly The Washington Water Power Company). When it was originally constructed in 1983, the Washington and Idaho Commissions retained a consultant to review the cost-effectiveness of the project. Based on evidence presented at hearings, the Commissions concluded that the project was not cost-effective and found that the utility's own studies showed that a natural gas power plant would have been less expensive from a lifecycle cost perspective. Both Commissions elected to exclude 10% of the investment from the utility's rate base. That disallowance has continued throughout the operating life of the plant.[82]

In New York in the late 1970s, Niagara Mohawk was building the Nine Mile Point nuclear plant, and suffered (like the rest of the industry) severe cost overruns. The New York Commission established a maximum cost for Nine Mile Point of $4.2 billion, and required the utility sponsors to absorb any costs in excess of that amount. This led to significant losses for the utilities.[83]

In the era of the 1980s, when a combination of high construction costs for coal and nuclear power, sharp inflation, a soft economy, and significant excess generating capacity occurred, more than 100 regulatory disallowances were considered by U.S. regulatory commissions. It was in this era that many of the principles addressed below for evaluating prudence and ruling on allowable costs evolved.[84]

c. Stranded Cost Treatment of Abandoned Project Costs

"Stranded costs" are the undepreciated value in a power plant that ceases to be "used and useful" to serve consumers.[85] A coal plant can cost over $1 billion to build and has an expected lifetime of about 40 years. The investment is recovered through depreciation expense over the life of the plant. In the case of a coal-fired power plant that is shut down because probable environmental compliance and operating costs exceed the value of the output, this can mean tens or even hundreds of millions of dollars of undepreciated investment remains on the books of the owners.

Typically coal plants that are facing a shutdown analysis today are older plants, and the original investment has been fully recovered or nearly so through depreciation expense included in electric rates. But every year that a plant operates, investments are made in renewals and replacements of components of a plant, and these investments are added to the "plant in service" balance upon which depreciation expense is calculated. These investments may also extend the plant's original service life. There is typically a significant plant balance for any operating plant—and often exceeding the original plant investment that was long ago fully depreciated.

If a plant is permanently closed, accounting rules require that the investment be removed from the "Plant in Service" classification. At that point, the regulator must decide whether the utility or its consumers will bear the burden of the unamortized expense. In some states this is dictated by law, and in others it is left to the Commission to make an

82 Washington Utilities and Transportation Commission, 1983.

83 Bang-Jensen, 1986.

84 Lyon and Mayo, 2005.

85 'Used and useful' is a term for describing a utility asset. 'Used' means that the facility is actually providing service, and 'useful' means that, without the facility, either costs would be higher, or the quality of service would be lower;" see Lazar, 2011, p. 38.

equitable determination of cost responsibility. We consider several examples here.

The Trojan nuclear plant was a 1,100-MW power plant near Portland, Oregon, which entered service in 1975. After a comprehensive analysis of the plant's economic viability, the primary owner, PGE, decided to close the plant in 1993 because the cost of needed retrofits exceeded the value of the project. The Oregon PUC initially allowed direct recovery of the undepreciated costs of the project. After a court rejected this, the Commission allowed an indirect offset to these costs, making the utility nearly whole for its remaining investment.

By contrast, when the state of California ordered its investor-owned utilities to divest themselves of their fossil-fired power plants in 1998-99, stranded cost recovery was fully and explicitly allowed, through a stranded costs charge applicable to both utility customers and those who chose other energy supply companies. The price utilities were able to secure when the plants were sold was less than the remaining undepreciated book value. The anticipated benefits of utility restructuring were such that the Commission determined that utilities should not bear losses due to above-market costs of older generating units. The utilities were allowed to recover 100% of the difference through a surcharge to electric consumers. This was pretty typical in the states where divestiture or corporate separation took place.

The issue that will arise with large coal plants is quite significant. Assume, hypothetically, that an existing plant cost $1 billion to construct in 1985. Since that time, most of the original capital has been recovered through depreciation expense, but minor upgrades during the operating life, in the meantime, put the remaining book value at $400 million.

If the utility looks at the cost of measures for SO_2, NOx, particulate, mercury and other air toxics, carbon combustion residuals, cooling water, and CO_2 that will be required to extend the life of the plant for 20 years, the new costs may exceed the original cost of the unit. Depending on the alternatives available, the utility may reach the conclusion that alternatives to these retrofits are less expensive. They are then faced with retiring a project with a significant investment still on the books. Regulators will need to examine these costs, and determine if they are appropriate for rate recovery under the legal framework of the individual state.

d. Prudence, Used and Useful, Rate Base, and Amortization

The evaluation by regulators of the costs to be allowed into utility rates varies by state, but nearly all use some basic concepts that are common:

Prudence: A utility's actions are considered prudent if they are reasonable and least-cost, given the facts and circumstances known or which reasonably should have been known at the time a decision is made. Simply because the decision to begin a project is prudent does not mean that the continuation or completion of the project is ipso facto prudent. A company must continually evaluate a project as it progresses to determine if the project continues to be prudent from both the perspective of need for the project and its impact on the company's ratepayers.[86]

Used and Useful: In most states, investments by utilities can be allowed into rates only if the assets are "used and useful." Although court interpretation of these terms has varied, in general "used" means that the facility is actually operated to provide service to consumers, and "useful" means that without the facility, either the cost of service would be greater, the quality of service would be worse, or both.

Rate Base: "Rate base" is a term used to describe the investments that utilities make in facilities that are included in rates. This consists of the original amount invested, any improvements made over time, less any depreciation expense collected during the time the asset has been in service. The recovery consists of a return *of* the investment (depreciation expense) and a return *on* the investment (rate of return).

Amortization: In many cases in which full rate base treatment is denied, most often for an asset that either was not completed or that has ceased to be used, regulators allow amortization of the remaining investment. This means that the utility is allowed to recover the actual amount of undepreciated investment over a period of years, but no profit, or rate of return, during the amortization

86 Most of this language was taken from Washington Utilities and Transportation Commission, 1984.

period.

In evaluating whether, and how, to allow utilities to collect for the undepreciated investment in projects no longer in service, the regulator will need to consider all of these issues. In many states, where the regulator finds that the utilities' actions are prudent, that the facility was used and useful for an extended period of time, but that it should be replaced with a newer, better resource, they have allowed full recovery of and on the undepreciated value.

Regulators can protect consumers by insisting that utilities seeking approval for compliance strategies prepare a comprehensive plant-specific and fleet-wide analysis of known and potential future costs, and present that to the regulator at the earliest point in time possible for review.

In some states, the regulator is limited to allowing only amortization of the undepreciated amount, without a return. This can create a perverse incentive in which the utility may be allowed to earn a return if it keeps an obsolete generating plant in service, but not if they prudently retire it. The authority of the regulator to encourage the right behavior will, to some extent, be limited by state law.

Several state regulators have found ways to compensate utilities for abandoned projects without using either traditional rate base treatment or traditional amortization. For example, Washington allowed a utility to transfer unused investment tax credits, which normally would have flowed to ratepayers over 30 years, to shareholders in a 3-year period, in exchange for the utility absorbing a portion of the investment in an abandoned nuclear plant.[87]

e. Strategy for Commissions Faced with Coal Retrofit Costs

For any regulator faced with such a coal retrofit scenario, the first challenge is to ensure that the full picture of potential future costs is known before any incremental costs are authorized for rate recovery. If the facility is cost-effective over its lifetime with the additional costs to be incurred, then it should be renovated, but only after the full review noted below. Because all of the requirements of the forthcoming EPA rulemakings are not yet known and the potential for additional regulations is always present, this challenge is not trivial.

Regulators can protect consumers by insisting that utilities seeking approval for compliance strategies prepare a comprehensive plant-specific and fleet-wide analysis of known and potential future costs, and present that to the regulator at the earliest point in time possible for review. Interested parties, including both supporters and skeptics of renovation, should be invited to comment on the analysis and participate in the evaluation.

At a minimum, utilities should be required to examine these potential costs when actual compliance proposals are submitted. Ideally utilities will examine the potential costs through an integrated process, in which retrofit or other compliance costs can be compared with all generation and non-generation alternatives.

The Mohave analysis is an excellent example of a unit-specific analysis undertaken prior to a commitment for major retrofit investments. The conclusion was that investments to extend the life of the plant were not justified. The Boardman analysis, discussed earlier, is an excellent example of an analysis undertaken in the context of an IRP for the utility. The conclusion was that minor retrofit costs to achieve a limited life-extension were justified, but major investments to achieve an extended life-extension were not. The eventual prudence of the utility decisions for both of these will be subject to review in general rate cases.

Regulators can insist on a checklist and cost estimate for all known retrofit requirements and strategies that may be imposed by the pending EPA rulemakings. They can insist on cost estimates of ranges of costs for compliance with potential CO_2 regulation, knowing these are more uncertain. Ultimately, like most elements of utility regulation, there is a role for reasoned judgment on the part of the regulator.

87 Washington Utilities and Transportation Commission v. Puget Sound Energy, Cause U-86-131, 1987.

f. Key Elements For An Integrated Resource Plan

One of the best ways to evaluate a prospective investment plan for renovation of a power plant is within a utility IRP. An IRP can consider a range of potential load scenarios, a range of potential economic scenarios, and a range of possible costs for both renovation of existing resources and acquisition of potential new resources. An IRP can compare the cost-effectiveness of demand-side measures with supply-side options.

For an IRP to perform these tasks well, it needs to be quite sophisticated in design, in software, and in data. Many utilities and regulatory consultants have appropriate tools for this work, but they are time-consuming and relatively expensive. When hundreds of millions of dollars are at stake, this can easily be a good investment.

The following list is just an example of the critical elements that are necessary for an IRP to adequately measure the value of an existing resource requiring extensive retrofit with a portfolio of alternative resources:

- Existing load shape
- Existing resource mix
- Available supply-side resources
- Available demand-side resources
- Ability to model fuel cost uncertainty
- Ability to model emissions regulation uncertainty
- Ability to model load growth uncertainty
- Ability to model changes in transmission interconnections
- Ability to value the benefit of short lead-time resources

With a sophisticated model, an open public process to utilize the model, adequate time to get the benefit of the IRP process, and attention to detail, regulators can get a good sense of what is likely to be economical and what is likely to be uneconomical. The best models can do no more than provide a range of reasonable outcomes under uncertainty. In the end, however, judgment is an essential element of the process.

7. Treatment in Rate Design

Ultimately whatever costs are allowed by regulators into the utility's revenue requirement are reflected in the rates paid by consumers. The customer will pay. But how? This section addresses the cost-causation basis of emission-related compliance costs and how these costs should be treated in retail rate design. In other words, the regulator must determine how to include in retail rates emissions control costs for plants that are renovated and the undepreciated costs for plants that are retired because it is uneconomical to renovate them.

Simply stated, although the investment costs for renovation are in part a function of the size of the plants, for rate design purposes emission costs are primarily associated with each kWh of energy produced by a generating plant, not with the plant's availability to meet peak demand.

Utilities have historically invested in emission control equipment for baseload power plants but have been hesitant to do so for intermittent or peaking units that are only used during the hours of the year when loads are at their highest levels. This is because the high capital cost of retrofits cannot be justified when a plant is seldom needed. As shown in Section 3, the renovation costs for a coal plant can easily exceed $1,000 per kW, whereas a modern low-emission peaker costs less than $1,000 per kW. The cost of a demand-response program to shave peak demand is typically much lower still.

Simply stated, coal plant renovation costs would essentially never be cost-effective to meet peak demand. The economic benefit of coal plants is in their ability to produce baseload energy at favorable costs.

Several principles should guide the inclusion of emission management costs in retail rates.

Ultimately whatever costs are allowed by regulators into the utility's revenue requirement are reflected in the rates paid by consumers. The customer will pay.

- **Focus on Long-Run Marginal Costs:** If we were building a new system with today's rules, what would the costs be?

- **Coal Units are Baseload/Intermediate, Not Peaking:** For nearly all utilities, coal plants operate as baseload and intermediate generating units.

- **Retrofit Costs Can Only Be Justified If Spread Over Many Hours:** This is the only way that spending the huge sums needed for plant renovation can be justified.

Rate case advocates will take strong positions on these issues. Those classes with higher load factors (more uniform use of power throughout the day and year) will advocate that the emission retrofit costs be treated as capital cost additions to the plant investment and allocated on the basis of class contribution to peak demand. That has the effect of imposing the retrofit costs on peak-hour usage, while leaving the low fuel costs of these units as a benefit to off-peak usage, where their consumption is dominant. Conversely, advocates for residential and small commercial consumers will advocate that the costs be assigned to energy usage.

Most of the emission control related costs are designed to clean up the energy production characteristics of the plant, and regulators should look to incorporate them into rates in a manner that is consistent with how the resources are used.

a. Clear Focus on Long-Run Marginal Costs

One principle of economics is that efficient allocation of resources occurs if certain pre-conditions are met, one of which is that all goods are priced at their relevant long-run marginal costs. This is the price at which the market can produce more of the item being purchased and cover all of the investment and operating costs of doing so.

This principle is particularly important for electricity, in which capital-intensiveness means that the capital costs of production can be 80% or more of the total cost. For a coal-fired power plant, for example, the investment-related costs can easily be twice as large a part of the total cost as the fuel cost.

When evaluating whether to renovate an existing coal plant, a utility (perhaps in the context of an IRP) will compare the cost of the renovated coal plant to the likely costs of other alternatives—new supply-side resources like natural gas power plants, renewable energy resources, and market purchases (plus the associated transmission costs), and energy efficiency and demand response resources. The mix of capital and operating cost for all of these options is different, but what really matters is the total cost.

In the case of substituting a new combined-cycle natural gas unit for a coal unit, the investment required in the natural gas unit may be much lower than the investment needed to renovate the coal plant, but the fuel costs could likely be higher. The only relevant comparison is on a total incremental cost basis—what costs would the utility and its consumers incur under each option, including capital costs, operating costs, fuel costs, and emission costs. This is a long-run marginal cost basis. A societal cost test would also include the public health and other environmental costs that remain after implementation of the option being examined. The regulator should insist that the lowest-cost option be preferred. But the regulator may then be faced with the question of regulatory treatment of the stranded costs of a retired unit.

b. Reflecting Emissions Costs In Cost Allocation and Rate Design

The causal relationship between plant life extension costs and potential fuel cost savings is relevant in determining how renovation costs are reflected in the rate design, because no customer or customer class should receive a disproportionate share of the cost as a result of the decision made. If choosing the least-cost option would raise residential rates by $0.02/kWh, but choosing a more expensive option would only raise residential rates by $0.01/kWh (with higher costs shifted to business consumers), the residential class would prefer the more expensive option—an irrational outcome.

A problem with rate design arises if regulators treat investment costs differently than fuel costs in the rate design. If the capital costs of a coal-plant retrofit are treated as fixed costs, are classified as capacity-related, and are allocated on the basis of peak demand, a large share would be assigned to the residential and small business classes. Conversely, if instead the utility built a gas-fired peaking plant (at a lower capital cost), and all of the higher fuel costs were treated as variable costs, classified as energy-related, and allocated on the basis of energy usage, a larger share would normally be assigned to the large commercial and industrial classes.

Hourly cost allocation methods that assign all costs of all resources equally to the hours when they are used can avoid these imbalances. Methodologies such as the peak-credit or equivalent-peak methods, that assign to peak hours only the costs that would be incurred for a peaker (not baseload plant costs) can avoid these imbalances. As a practical matter, the cost allocation methodology should ensure that the least-cost solution for the total utility system is also the least-cost solution for each of the customer classes on the system. Some methods that allocate capital costs of baseload power plants based on class usage at peak hours have the effect of shifting costs associated with baseload generation to those customer classes with high on-peak operation, even though their peaking needs are typically met with lower-emission natural gas generating plants.

One solution to this is to use a long-run marginal cost allocation study to assign all costs on the system between customer classes. About one third of states already do this. Another is to examine only the incremental costs of various alternatives, but to allocate all of the incremental costs between classes on a per-kWh basis, so that the least-cost option affects all classes equally. The best method will vary from state to state, but the principle should be the same: cost allocation should not make any customer class better off if a higher total cost alternative is pursued.

Generally speaking, the emissions of power plants are in proportion to their generation in kWh. Logically, the cost of ameliorating those emissions should be paid for in proportion to the kWh usage. One easy way to ensure that all classes benefit from the least-cost solution to emissions reduction is to allocate the incremental cost of achieving that benefit on a kWh basis among all classes. This is a different approach than many commissions use for allocating the investment-related costs of existing baseload coal-fired power plants, but may be the only effective way to ensure that all customers benefit from the choice of the least-cost option.

Figure 18 shows some of the methods used to classify and allocate production costs among customer classes. They include methods that are most focused on the peak hours of the year, methods that focus on both peak demand and baseload energy, and an approach that ignores peak capacity requirements entirely.

Figure 18

Methods of Allocating Production Costs Among Customer Classes[88]

Method	General Description	Appropriate Application
Peak Responsibility	Class contribution to system coincident peak demand (1 hour, peak hours in peak months, or multi-hour).	Systems with very high load factors and all generating capacity having similar cost characteristics.
12 Monthly Peaks	Average of class contribution to system coincident peak hour(s) in each of 12 months.	Systems with very high load factors, different classes peaking in different months, and all generating capacity having similar cost characteristics.
Non-Coincident Peak	Highest demand of each class at whatever hour that demand occurred.	
Average and Excess Demand	Percent of costs equal to system load factor allocated between classes on average demand; additional costs allocated to class contribution to system coincident demand in excess of class average demand.	Systems with different clases peaking in different times, and all generating capacity having similar cost characteristics.
Loss of Load Probability	Those costs deemed related to peak demand assigned based on probability of insufficient capacity to meet load.	Systems with significant seasonal capacity constraints, including hydro or renewables.
Base-Intermediate-Peak	Fixed and variable costs of plants allocated to hours in which those plants operate, divided among classes based on class energy usage during those hours.	Systems with mix of capital-intensive baseload plants, and less capital-intensive intermediate and peaking plants.
Peak Credit (also known as Equivalent Peaker)	Percentage of baseload plant costs equal to the cost of a peaking unit allocated on basis of peak demand; remaining costs allocated on basis of energy usage.	Systems with mix of capital-intensive baseload plants, and less capital-intensive intermediate and peaking plants, and in particular, systems with storage hydro capacity.
Pure Energy	All costs allocated on basis of energy usage.	Systems with excess capacity.

88 Adapted from Lazar, 1992.

c. Time-of-Use Element to Emissions

Another approach to fair allocation of plant emission compliance costs is to employ a time-of-use methodology and then flow those costs through into the retail rates based on the time when each class uses power. This is often referred to as the Base-Intermediate-Peak cost allocation methodology, in which the costs of baseload power are allocated to all hours equally, while the cost of peaking power plants are allocated only to the peak hours. This is used to ensure that all classes pay for the resources that serve them.

Because coal plants generally operate as baseload or intermediate units, this approach would assign the renovation costs to a broad number of hours, not to the peak capacity function. If the regulator does not generally use a long-run marginal cost approach for cost allocation, this is a good alternative.

Figure 19

Illustrative Retail Rates With and Without $30/ton CO_2 Costs for Gas and Coal

		Before Emission Costs	Emission Costs	With Emission Costs
Customer Charge	$/Month	$10.00	$ –	$10.00
Demand Charge	$/kW	$10.00	$ –	$10.00
On-Peak Energy Charge *Gas at the margin*	$/kWh	$0.08	$0.015	$0.10
Off-Peak Energy Charge *Coal at the margin*	$/kWh	$0.05	$0.03	$0.08
Ratio of On- Peak to Off-Peak	%	160%	$30/ton CO_2	119%

This may seem counterintuitive that off-peak would be more expensive, because one principle of time-of-use pricing is to make the off-peak power less expensive to reduce pressure on the need to add capacity to meet higher peak loads. If the cost of lowering emissions, however, is a significant additional cost for a coal plant, mitigated in part by the higher fuel cost for a natural gas unit, then it is appropriate that the internalization of emission costs would narrow the percentage gap between on-peak and off-peak rates.

In a dynamic pricing framework in which hourly prices are implemented or prices are higher during critical peak periods, a slightly different approach may be needed. First, a long-run marginal cost approach will still work well. During off-peak hours, the cost of building and operating a baseload plant (including emission and CO_2 costs) is applicable. In the extreme peak hours, when system stability is at risk, the long-run marginal cost is either the cost of a peaking generator such as an internal combustion engine, or the cost of a demand-response program, whichever is lower. The dynamic price can gradually be raised until it triggers demand-response, or until it reaches the cost of building and operating a new peaker.

Figure 19 shows on an illustrative basis how a uniform cents/kWh surcharge for emission compliance recovers emission costs from all units and reduces the relative percentage spread between on-peak and off-peak rates for a demand-metered commercial or industrial customer. It assumes that the marginal emission costs from coal are twice as great off-peak, consistent with Figure 11, showing that coal plant (off-peak) emissions are about two times those from natural gas (peaking) units.

The same logic may apply to some hot-region utilities with respect to seasonal rates. In the summer, the utility may draw on natural gas combustion turbines to meet incremental power needs, whereas in the winter it uses primarily baseload coal units. If the renovation costs are collected based on the marginal costs at the times when the coal-fired units and gas turbines are operated to serve incremental load, it will have the effect of causing larger increases in the off-season rates than the peak-season rates. Again, narrowing the gap between the rates is justified by the incremental costs of emission compliance.

d. CO_2 Costs

The discussion above has primarily been focused on the pollution control retrofit costs for existing power plants. If state, regional, or federal legislation results in a price for CO_2 emissions, then regulators will need to address these expenses in the ratemaking process.

Where CO_2 is subject to a price, utilities will need to either acquire allowances for those emissions, pay a tax for those emissions, or will be given free allowances that they can either use or sell. Figure 20 describes three different methods for CO_2 regulation, and two alternatives that may be allowed to meet CO_2 emission mandates, all of which will have implications for utility regulators.

In any of these approaches, there is a market value for CO_2 emissions, and this value needs to be built into the price of electricity. Ideally every customer should see, at the margin, the marginal cost of CO_2 emissions, whether it is a tax, a free allowance that can be sold, or a purchased allowance that can be avoided.

There are several important elements here.

First, if the utility receives some of its needed allowances for free, it is still important to reflect the marginal cost of incremental allowances in the marginal price for electricity. This marginal price is equally relevant if the utility receives surplus allowances, if it is allowed to sell the surplus in a competitive market. An inverted block rate design or rolling baseline rate design with the CO_2 allowance costs reflected only in the incremental block rate may be the best way to do this, so that customers see the full long-run marginal cost for incremental usage.

Another issue is that the costs of CO_2 emissions from coal plants should generally be assigned to the hours when the coal unit is used. If the utility has time-of-use rates,

Figure 20

Alternative Forms of CO_2 Regulation

Method	General Description	Ratemaking Elements	Example
Carbon Tax	Government sells rights to emit CO_2 at a defined price. All emitters must purchase rights.	The cost of the carbon tax becomes an element of utility expense, either directly for power the utility generates, or embedded in purchased power expense. Commission must determine if a least-cost path was followed.	*British Columbia, Canada*
Cap and Trade	Government gives free allowances to historical emitters, declining in number over time. They can trade among themselves.	The revenues from sales of excess allowances, and the purchase costs for needed allowances are elements of utility expense. Allowance costs will be embedded in purchased power prices. Commission must determine if a least-cost path was followed.	*California Air Resources Board implementation of AB32 beginning in 2013*
Cap and Auction	Government auctions allowances to emitters (and perhaps others), declining in number over time. Purchasers can trade among themselves.	The cost of the allowances becomes an element of utility expense, either directly for power the utility generates, or embedded in purchased power expense. Commission must determine if a least-cost path was followed.	*Regional Greenhouse Gas Initiative (New England)*
Offsets	Utility purchases carbon offesets from forestry or other carbon-offsetting activities to meet all or a portion of the allowance requirement under a carbon tax or carbon cap framework.	The cost of the offsets becomes an element of utility expense, either directly for power the utility generates, or embedded in purchased power expense. Commission must determine if a least-cost path was followed.	*Permitted in the California Cap and Trade System up to 4% of total compliance obligation*
Seques-tration	Utility installs equipment on a fossil generator to capture CO_2 before it is emitted, and store it in a geological formation or chemical form.	The cost of the sequestration equipment becomes an element of rate base and operating expense for the utility. Commission must determine if a least-cost path was followed.	*Experimental technology under development at several locations*

these costs should be more predominant in the rate design during the off-peak hours, when coal is likely the dominant fuel (and may be the marginal fuel). The on-peak hours are more likely to be served at least in part with lower-emission power from natural gas units (with higher fuel costs that are already reflected in on-peak charges). Although both on-peak and off-peak costs increase as a result, the effect of this is to slightly mute the *relative* on-peak/off-peak price signals that guide consumption and demand-response efforts, consistent with the focus on long-run marginal costs (including environmental costs) that is the thesis of this section.

A third issue is that utilities are adding carbon-free resources, including renewable energy and (in a few cases) planned new nuclear units. It is unlikely that these carbon-free resources will be the marginal (dispatchable) resource for more than a few hours per year; rate design should continue to focus on the long-run marginal cost of least-cost resources. In a future scenario, this might be nuclear units for baseload, wind on an as-available basis backed by pumped storage hydro, and solar during peaking periods; the costs might be very different from today's costs, but the principle is unchanged: replacement costs for new resources, including appropriate environmental costs, should form the basis of retail rates.

A long-run marginal cost approach to rate design (independent of whether marginal costs are the basis of cost allocation between classes) can work well for this. During off-peak hours, incremental generation may come from coal units, and the CO_2 costs associated with coal would be the marginal cost in those hours. During on-peak hours, while the coal plants are still running, the marginal generation more likely comes from natural gas units with higher fuel costs but lower CO_2 costs and the long-run marginal cost would be based on that of a gas-fired unit. The effect of tracking these marginal costs will be to increase prices at all hours, but it likely will moderate the difference between on-peak and off-peak prices, because the emissions are generally lower for the marginal (gas-fired) units dispatched to meet incremental loads at the time of system peaks.[89]

The same principle should apply to utility integrated resource planning efforts, whether they are distribution utilities with default service obligations or fully integrated utilities. The IRP needs to continuously look at existing and new resource options, on a full-cost basis, with environmental costs incorporated. The estimates for future environmental costs will inevitably be imprecise—but *zero* is clearly the *wrong* figure to assume for future CO_2 costs and for future costs for other emissions, given the panoply of environmental and public health issues implicated by power system operations.

89 An offsetting factor to this in rate design is that most current rate designs do not fully reflect marginal line losses or marginal generation reserves costs during on-peak periods. These marginal losses can be as high as 30% during critical peak periods. See Lazar and Baldwin, August 2011.

8. Conclusions

There are existing coal-fired power plants that will become uneconomical as a result of a series of updated environmental regulations, including the prospect of carbon regulation. Some of these may have been already rendered uneconomical on a running-cost basis due to low natural gas prices, improved technology for renewable resources and energy efficiency, and the cost of routine maintenance and upkeep of the coal units, many of which are old. All these forces and trends together will put further pressure on the role of coal in a least-cost supply portfolio.

The role of the regulator is to ensure that utilities have a framework in which to operate that is predictable, sensible, and provides for reliable electric service at least cost.

The role of the regulator is to ensure that utilities have a framework in which to operate that is predictable, sensible, and provides for reliable electric service at least cost. The regulator must ensure that money is not wasted on uneconomical units, but also, if utilities do invest prudently, that they are able to recover their costs and get a fair return on their investments. This includes both the incremental costs to meet emission requirements on a least-cost basis, and fair treatment of the costs of generating units that are retired after providing economical service.

For plants that are not fully depreciated but are retired due to the high cost of emission management, regulators will need to decide whether to allow recovery of these costs in rates. This decision should be guided by traditional regulatory principles of prudence and the legal framework of each state. The goal of the regulator should be to make the utility that does the prudent thing better off than the utility that chooses the option that carries higher total costs to society.

Looking ahead, regulators need to insist that utilities regularly evaluate their future resource plans and fully incorporate best estimates of future environmental, public health, and safety regulations. IRPs, long-term power contracts, transmission expansion, renewable resource development, and energy efficiency investments will all be affected by assumptions as to future environmental regulations. To fail to consider the likely, probable, and potential costs is to hide from the future.

The significant number of EPA rulemakings underway addressing many different aspects of power plant operations and emissions makes this a difficult time for state utility regulators. They must look ahead 20 to 30 years to make reasoned decisions. This requires a thoughtful process for ensuring that utilities study all their reasonable options before committing to the first step of investment in plant rehabilitation and upgrade that ratepayers will have to pay.

Otherwise there is the risk that today's older coal plants could become the power sector equivalent of a fully-restored $500,000 Edsel of tomorrow. Interesting, perhaps, but not a good choice for everybody.

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Appendix 1:
Acronym Glossary

ACI Activated Carbon Injection

BART Best Available Retrofit Technology

CAA Clean Air Act

CO_2 Carbon Dioxide

CO_2e Carbon Dioxide Equivalent

CCR Coal Combustion Residuals

CCS Carbon Capture and Storage

CPCN Certificates of Public Convenience and Necessity

CPUC California Public Utilities Commission

CSAPR Cross-State Air Pollution Rule

DOE US Department of Energy

DSI Dry Sorbent Injection

EPA US Environmental Protection Agency

ETS Emissions Trading Scheme

FGD Flue Gas Desulfurization

FIP Federal Implementation Plan (see SIP)

GHG Greenhouse Gas

Hg Mercury

IRP Integrated Resource Plan

kW Kilowatt

MACS Mohave Alternatives and Complements Study

MW Megawatt

NOx Nitrogen Oxide

NAAQS National Ambient Air Quality Standards

NERC North American Electric Reliability Corporation

NLNB/MOFA New Low NOx Burners with Modified Overfire Air

NLNB/MOFA/SNCR New Low NOx Burners with Modified Overfire Air and Selective Non-Catalytic Reduction

NSPS New Source Performance Standards

NPDES National Pollutant Discharge Elimination System

O&M Operation and Management

OCC Oklahoma Corporation Commission

PGE Portland General Electric

PM Particulate Matter

PSD Prevention of Significant Deterioration

RCRA Resource Conservation and Recovery Act

SCE Southern California Edison

SCR Selective Catalytic Reduction

SIP State Implementation Plan

SNCR Selective Non-Catalytic Reduction

SO_2 Sulfur Dioxide

VOC Volatile Organic Compound

ZLD Zero Liquid Discharge

Appendix 2

EPA Rulemakings Affecting Power Plant Operations

The Cross-State Air Pollution Rule

Under the Clean Air Act (CAA), National Ambient Air Quality Standards or "NAAQS" define the maximum permissible concentrations in the air for certain pollutants, known as "criteria pollutants." NAAQS have been set for carbon monoxide, particulate matter, sulfur oxides, oxides of nitrogen, lead, and ozone.[90]

Based on air monitoring data, the EPA determines whether areas in states meet or do not meet these standards. On this basis, the EPA designates areas as being in "attainment" or "non-attainment" of the NAAQS. States are required to submit federally enforceable plans, known as state implementation plans or "SIPs," to demonstrate that they have in place air programs that will ensure the state's continued attainment with NAAQS, or—if in non-attainment—how the state will come into attainment by specific deadlines. Under certain circumstances, the EPA rather than states will promulgate a Federal Implementation Plan or "FIP" for the state.

In the Cross-State Air Pollution Rule (CSAPR), the EPA seeks to "limit the interstate transport of emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) that contribute to harmful levels of fine particle matter (PM2.5) and ozone[91] in downwind states."[92] These emissions are carried downwind as SO_2 and NOx or, after being transformed in the atmosphere, as fine particles or ozone. By reducing emissions in upwind states, air quality in downwind states is improved, thereby helping downwind states meet NAAQS.[93]

Section 110(a)(2)(D)(i)(I) of the CAA requires states to prohibit emissions that "contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national … ambient air quality standard…."[94] The EPA has found that emissions of SO_2 and NOx in 27 eastern, midwestern, and southern states (including the District of Columbia) violate this "significant contribution" standard with regard to at least one of the following air quality standards: the annual PM2.5 (fine particulates) NAAQS (developed in 1997), the 24-hour PM2.5 NAAQS (2006), and/or the ozone NAAQS (1997).[95] The rule also sets out a process for determining each upwind state's responsibility to protect downwind air quality (i.e., the

90 Code of Federal Regulations, Title 40, Part 50.

91 Ground-level ozone is a pollutant created through the interaction of NOx, volatile organic compounds or "VOCs," and sunlight.

92 Code of Federal Regulations, Title 40, Parts 51, 52, 72, 78, and 97. These states include Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. The EPA will address these emissions through Federal Implementation Plans.

93 The rule defines the obligations of upwind states to reduce pollution "significantly contributing to downwind nonattainment and maintenance areas" depending on the magnitude of a state's contribution; cost of controlling pollution from various sources; and air quality impacts of reductions; see U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule: Reducing Air Pollution, Protecting Public Health."

94 U.S. Code, Title 42, § 7410(a)(2)(D)(i)(I), § 110(a)(2)(D)(i)(I).

95 The EPA has also proposed to extend the rule's ozone-related NOx reductions to six additional states. See Figure ___ for a list of states covered by the final rule and the emissions they will need to control, including the six states proposed in the supplemental notice of proposed rulemaking to be included for ozone season NOx emission reductions; see U.S. Environmental Protection Agency, "Fact Sheet: The Cross-State Air Pollution Rule," p. 5.

amount of emissions reductions that state must make).

Emissions control technology for NOx includes Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). The typical controls for SO_2 are flue gas desulfurization (FGD) and dry sorbent injection (DSI).[96]

The rule also provides for an alternative compliance route by creating several intra- and interstate SO_2 and NOx trading programs:

- Annual SO_2 Group 1 Sources (i.e., those that need to make larger reductions);
- Annual SO_2 Group 2 Sources (i.e., those that need to make smaller reductions);
- Annual NOx emissions; and
- Ozone-season NOx.

Trading is allowed among emissions sources in the same program (e.g., ozone season NOx). For 2012 compliance, the EPA will allocate emissions allowances to affected facilities; states can develop their own allocation schemes by 2014.

Phase 1 compliance begins January 1, 2012 for annual SO_2 and NOx reductions and May 1, 2012 for ozone-season NOx reductions. More stringent SO_2 reductions begin January 1, 2014 for "Group 1" states (Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin).

Mercury/Air Toxics Rule

The 1990 CAA amendments require the EPA to develop an emissions control program for certain listed toxic air pollutants. Power plants are responsible for half of the nation's mercury emissions and half of the acid gases. The EPA estimates that there are approximately 1,350 coal- and oil-fired units at 525 power plants that will be subject to this rule. On March 16, 2011 the EPA proposed the first national standard to reduce mercury and other toxic air pollution from coal- and oil-fired power plants, the "National Emissions Standards for Hazardous Pollutants," commonly referred to as the "Mercury/Air Toxics Rule."[97] This rule regulates emissions of mercury, arsenic, other toxic metals, acid gases, and organic air toxics such as dioxin.

The legal standard for toxic emissions from *existing* sources states that Maximum Achievable Control Technology (MACT) "shall not be less stringent, and may be more stringent than the average emission limitation achieved by the best performing 12% of the existing sources…in the category or subcategory…" This calculation is referred to as the "MACT floor" and does not take cost into account but does reflect what existing and deployed technology can do. The EPA can require what are referred to as "beyond-the-floor" reductions if cost-effective technologies are available. Section 112 states that "new" source controls "shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator."

The proposed Mercury/Air Toxics Rule contains significant flexibility provisions, including facility-wide and monthly emissions averaging, the use of surrogate pollutants, and fuel-switching to coals with lower mercury or chlorine content. Un-scrubbed units will need to install "electrostatic precipitators" or fabric filters for particulates or make use of alternative sorbents such as activated carbon or halogen additions for mercury and DSI (e.g., Trona, Sodium Bicarbonate, or Hydrated Lime, i.e., dry-scrubber technologies) for strong acids (hydrochloric and hydrofluoric).

The schedule for compliance under the Mercury/Air Toxics Rule varies for existing and new sources. Existing sources are required to meet standards within 3 years from the date of the final rule, with the opportunity for a 1-year extension. Compliance for new and reconstructed sources will be required going forward on issuance of the final rule.

Regulation of GHGs

The EPA's plans to regulate CO_2 and other GHGs are based on several administrative actions and rules, including the GHG Reporting Rule, the Tailoring Rule, permitting, and New Source Performance Standards.[98] These are briefly described here.

96 For a discussion of compliance technologies, see, e.g., Foerter, 2010.

97 U.S. Environmental Protection Agency, March 16, 2011.

98 For a more complete discussion of the EPA's GHG Reporting Rule, Endangerment Finding/Light Duty Vehicle Rule, Johnson Memorandum Reconsideration, Tailoring Rule, and New Source Performance Standards, see Farnsworth, 2011, pp. 11-14.

Reporting

In October 2009, the EPA proposed a GHG Reporting Rule that requires nearly all facilities that emit 25,000 metric tons or more per year of CO_2 equivalent (CO_2e)[99] emissions to monitor their GHG emissions and submit detailed annual reports to the EPA starting in 2011. The Final Rule was issued in October 2010, and March 2011 was the first reporting deadline.[100]

The Tailoring Rule

The Tailoring Rule, proposed by the EPA in October 2009, applies GHG regulations to major sources.[101] The EPA proposed this rule because it recognized that the existing thresholds in its air permit programs were not realistic for GHGs. Existing thresholds for air pollutants were far too low (e.g., 50-100 tons per year) to apply to GHGs, which are emitted in greater amounts. The EPA thus chose to "tailor" its GHG thresholds to avoid capturing numerous small sources under federal GHG permitting programs.

Permitting

Power plants are subject to air quality permit requirements and regulations for GHGs will be implemented in several phases. In January, the EPA issued phase one of its GHG permitting rule and followed with a second phase in July. The first phase requires new and modified sources that already needed an EPA "major source" air permit (and which emit at least 75,000 tons per year of GHGs) to include in that permit a limit on GHG emissions. Under Phase II, a source that emits over a threshold of 100,000 tons per year, whether or not the source already requires EPA permits for any other pollutant (or whose major modification results in greater than 75,000 tons per year) must acquire a permit.

Preconstruction or "PSD" Permits

The CAA requires a company planning to build a new power plant or perform major modifications on an existing plant to get a preconstruction permit under the Prevention of Significant Deterioration (PSD) program. The purpose of the PSD program is to prevent new sources of pollution from degrading air quality. The CAA requires a PSD permit for a facility being planned for an area in attainment for NAAQS or if the facility is going to emit a pollutant for which no air quality standards have been created, which is the case with GHGs. Facilities subject to PSD permitting requirements must conduct Best Available Control Technology (BACT) reviews to determine what type of GHG control technology they will have to install to meet GHG permit limits.

Title V or "Operating" Permits

After July 1, 2011, sources that emit over 100,000 tons per year of GHG will need an operating permit. These permits are typically issued once a source has begun operation and typically do not include additional control requirements. Title V operating permits, issued by state or local permit authorities, are intended to be comprehensive and bring together all state and federal emissions control requirements in one document.

New Source Performance Standards

The CAA requires the EPA to establish categories of major polluters and to develop performance standards for new or modified sources in each category.[102] In December 2010, the EPA entered into a settlement in which it agreed to develop NSPS for new and modified electric generators and emission guidelines for existing electric generators by July 26, 2011 and final regulations by May 26, 2012.[103]

Under Section 111(b), the EPA sets emissions limitations on new and modified sources within each source category that it has completed (e.g., Stationary Gas Turbines). The EPA is required to take "into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements…" as the EPA determines.[104]

With regard to existing sources, Section 111(d) requires the EPA to issue "guidelines" to the states that they must follow in preparing state plans to meet the standards for existing categories. Under Section 111(d), states are required to submit a plan to impose NSPS requirements on all existing sources in the state. Guidelines contain targets

99 CO_2e is a measure of the global warming potential of all GHGs.

100 Federal Register, October 28, 2010.

101 Federal Register, 2009.

102 Pearson and Monast, 2011, p. 2.

103 U.S. Environmental Protection Agency, "Settlement Agreements to Address Greenhouse Gas Emissions from Electric Generating Units and Refineries Fact Sheet."

104 U.S. Code, Title 42, § 7411(a)(1), § 111(a)(1).

based on demonstrated controls, emissions reductions, costs, and installation and compliance timeframes. Standards for existing sources can be less stringent than standards for new or modified sources. States have 9 months after the publication of guidelines to submit plans for EPA approval.

Although the EPA is expected to issue performance standards for GHGs soon, it is not clear what form these standards may take. According to several commentators, the EPA should have a significant degree of flexibility in setting NSPS for GHGs:[105]

> *Given agency discretion to define uncertain statutory terms like "best system of emission reduction," and given the potential of compliance flexibility mechanisms to reduce costs while preserving total emissions reduction goals, EPA and the states should be able to fit a variety of flexible approaches into the statutory criteria for performance standards.*[106]

If the EPA is able to grant compliance flexibility to states, this could allow for such approaches as allowance trading and other related, market-based compliance approaches.

Water and Solid Waste Regulations

In addition to being subject to various air regulations, electric generators will be affected by the outcome of other rulemakings under the Clean Water Act and the Resource Conservation and Recovery Act.

Cooling Water Rule (316(b)) [107]

The proposed 316(b) rule will establish requirements for all "existing" power generating facilities and existing manufacturing and industrial facilities that (a) withdraw more than 2 million gallons per day of water from waters of the United States, and (b) use at least 25% of the water they withdraw exclusively for cooling purposes. The EPA estimates that 670 of these facilities are power plants, including both coal- and natural gas-fired units.

The proposed national requirements, which would be implemented through National Pollutant Discharge Elimination System (NPDES) permits, would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the Best Technology Available (BTA) for minimizing adverse environmental impact.

The purpose of the rule is to "minimize adverse environmental impacts, including substantially reducing the harmful effects of impingement and entrainment."[108] Fish and smaller organisms die because they are either unable to swim away from water intakes and are "impinged" against the screen or pass through screens and become "entrained" in the cooling system. The 316(b) rule would set performance standards for fish mortality caused by impingement and would establish a requirement that entrainment standards be developed by facilities on a case-by-case basis.

New Facilities

The proposed rule would require new units constructed at an existing facility to comply with provisions for impingement and entrainment mortality based on a closed-cycle system. These standards are similar to standards set out for new facilities. This can be accomplished by either including a closed cycle system or by making any other

105 See, for example Wannier et al, 2011, and Litz et al, 2011.

106 Wannier et al, 2011, p. 1.

107 Hewitt, 2010. The EPA is also developing a "Steam Electric Effluent Limitations Guideline" that focuses on the steam electric subcategory of all electric generating activities, including fossil-fueled (coal, oil, gas) power plants. A major focus of the Effluent Rule is on toxic pollutants released into wastewater and ash ponds as part of the flue gas desulfurization process. According to the EPA, the schedule for the development of an effluent rule requires the EPA to collect technical and financial information for analysis, an effort that is underway. No rule has been proposed yet. The EPA intends to issue proposed regulation in mid-2012 and a final rule in late 2013. The Rule will have an effective date 60 days after publication. Dischargers are likely to be required to apply for NPDES permits. Compliance with a rule is expected to start 3 to 5 years after the final rule, 2016 to 2018.

108 U.S. Environmental Protection Agency, March 28, 2011.

changes that would result in impingement and entrainment reduction equivalent to the reductions associated with closed-cycle cooling.[109]

Coal Combustion Residuals [110]

The EPA proposed a rule on Coal Combustion Residuals (CCRs) from electric utilities in June 2010 but has not set a date for a final rule.[111] CCRs are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and FGD materials. In 2008, over 136 million tons of CCRs were produced in the United States. This waste is currently disposed of in various ways. It is placed in approximately 300 CCR landfills and in 584 surface impoundments at approximately 495 coal-fired power plants across the nation. It is also placed in mines or is "beneficially" used (e.g., in building materials).[112]

Applying its solid waste authority under the federal Resource Conservation and Recovery Act (RCRA), the EPA has proposed two alternative approaches for regulating the disposal of CCRs produced by electric utilities and independent power producers. The first and more stringent approach, designated "Subtitle C," would treat CCRs like hazardous waste.[113] For example, under this approach, parties who create, transport, or store CCRs would be subject to various requirements including permitting, ground water monitoring, and financial assurance. Existing landfills would be required to install groundwater monitoring within one year of the effective date of the rule. If monitoring were to show groundwater contamination, remedial action would be required. New or expanded landfills would be required to install composite liners and groundwater monitoring before the landfill begins operation.

Under the less stringent "Subtitle D" approach, CCRs would continue to be classified by the EPA as a "non-hazardous" waste. Facilities would be subject to national minimum criteria governing CCR disposal. Subtitle D engineering requirements (e.g., liners and groundwater monitoring) would be similar to Subtitle C. Under either proposal, an exemption from regulation would remain in place for "beneficial uses" of CCRs.

109 U.S. Environmental Protection Agency, March 2011.

110 Discussion of the EPA's proposed Coal Combustion Residual Rule based, in part, upon presentation by Devlin, 2010.

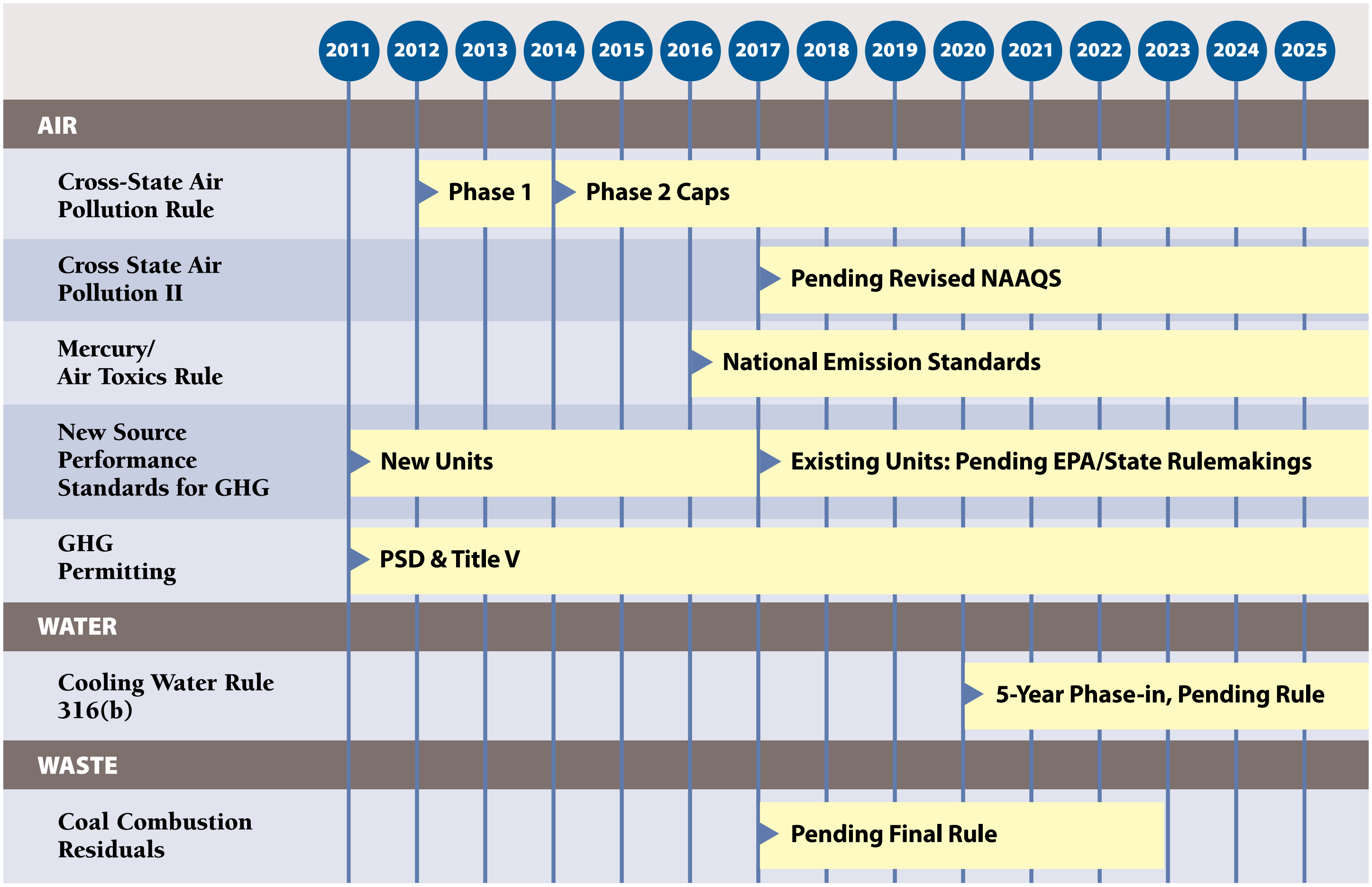
111 Federal Register, June 21, 2010. In its May 2010 pre-published version of the proposed rule, the EPA indicated that it "has not projected a date for a final rule at this time." Discussion of the EPA's proposed Coal Combustion Residual Rule based on presentation by Devlin, 2010.

112 According to the EPA, "[b]eneficial use refers to use of material that provides a functional benefit—that is, where the use replaces the use of an alternative material or conserves natural resources that would otherwise be obtained through extraction or other processes to obtain virgin materials;" see U.S. Environmental Protection Agency, "Frequent Questions: Coal Combustion Residues - Proposed Rule," 2011.

113 RCRA is divided into subtitles. Subtitles C and D set out the framework for the EPA's solid waste management program. Subtitle C establishes the framework for managing "hazardous" waste (from generation to its disposal), whereas Subtitle D sets out a system for managing primarily "non-hazardous" waste.

Figure 21

Implementation Timeline for EPA Regulations[114]



Potential Flexibility in the EPA's Air Regulations

In each of the air regulations described here there exists opportunities for flexibility in meeting compliance requirements. Under the CSAPR, the adoption of cap-and-trade, a market-based compliance mechanism, will allow emitters to trade allowances to meet compliance obligations in a least-cost manner.

The Mercury/Air Toxics Rule contains a number of significant flexibility provisions. First, it allows for facility-wide averaging for all emissions of hazardous air pollution from existing units within the same subcategory, thereby providing environmentally equivalent but less costly ways of achieving emissions standards. Second, the proposed rule would allow for averaging of facility emissions to accommodate generators' operational variability. Averaging would be allowed over a 30-day period. Third, the proposed Mercury/Air Toxics Rule also provides for flexibility and less costly compliance demonstration methods through the use of "surrogates" (i.e., the control of one pollutant as a proxy for others). This would allow an emitter to demonstrate control over the emission of one pollutant that typically accompanies another pollutant by simply demonstrating control of the first pollutant. For example, there are emissions limits for particulate matter as a surrogate for non-mercury metals.

With regard to GHG regulation, by focusing first on large emitters of GHGs, the central effect of the EPA's Tailoring Rule focuses on fewer larger sources of GHGs.

114 Adapted from Sierra Club, July 11, 2011.

Permitting requirements direct application of the rule to sources already subject to the standard and then only to larger sources first. The BACT standard applied in PSD permits also takes into account "energy, environmental and economic impacts and other costs." As rulemakings go forward, stakeholders will have the opportunity to provide the EPA with input as to cost-effectiveness. With regard to New Source Performance Standards, although no guidance has been issued by the EPA, the analysis under CAA Section 111 for setting NSPSs allows for the consideration of cost, non-air quality health and environmental benefits, and energy requirements. The standard also emphasizes the "best system" of emissions reduction and avoids imposing specific technology standards.

Potential Flexibility in the EPA's Water Regulations

There is potential for flexibility in meeting compliance requirements of the 316(b) cooling water rule. For example, the 316(b) rule provides existing sources with choices of how to comply with BTA standards for impingement. For addressing entrainment mortality, the rule provides for facilities to study and develop information as part of the permit application process and then establishes a process by which the BTA for that facility would be determined. Existing sources have 8 years to install screens or nets or to reduce cooling water intake velocity. Existing fossil and nuclear units that are required to build cooling towers have, respectively, 10 and 15 years to do so. For new facilities or modifications of existing facilities, the EPA allows generators to build a closed-cycle system or to make "other changes that would result in impingement and entrainment reduction equivalent to the reductions associated with closed-cycle cooling."[115]

Potential Flexibility in the EPA's CCR Regulations

The EPA's proposed CCR regulations contain significant potential for compliance flexibility. Despite one avenue of regulation (Subtitle C) being especially restrictive and more expensive to implement, the rule as actually proposed contains a number of less stringent alternatives. It also preserves certain exemptions to CCR regulation. In addition, although the EPA proposed a rule in May 2010, the EPA has decided to refrain for the moment from setting a date for a final rule, leaving regulated entities time to consider alternatives and plan their compliance strategies.

115 U.S. Environmental Protection Agency, March 28, 2011.

Figure 22

The Cross-State Air Pollution Rule Programs and Affected States [116]

	Reducing Emissions of NOx During the Ozone Season *(1997 Ozone NAAQS)*	Reducing Annual Emissions of SO_2 and NOx *(1997 Annual PM2.5 NAAQS)*	Reducing Annual Emissions of SO_2 and NOx *(2006 24-hour PM2.5 NAAQS)*
Alabama	◆	◆	◆
Arkansas	◆		
Florida	◆		
Georgia	◆	◆	◆
Illinois	◆	◆	◆
Indiana	◆	◆	◆
Iowa	◆ *(proposed)*	◆	◆
Kansas	◆ *(proposed)*		◆
Kentucky	◆	◆	◆
Louisiana	◆		
Maryland	◆	◆	◆
Michigan	◆ *(proposed)*	◆	◆
Minnesota			◆
Mississippi	◆		
Missouri	◆ *(proposed)*	◆	◆
Nebraska			◆
New Jersey	◆		◆
New York	◆	◆	◆
North Carolina	◆	◆	◆
Ohio	◆	◆	◆
Oklahoma	◆ *(proposed)*		
Pennsylvania	◆	◆	◆
South Carolina	◆	◆	
Tennessee	◆	◆	◆
Texas	◆	◆	
Virginia	◆		◆
West Virginia	◆	◆	◆
Wisconsin	◆ *(proposed)*	◆	◆

116 Based on U.S. Environmental Protection Agency, "Fact Sheet: The Cross-State Air Pollution Rule."

The Regulatory Assistance Project (RAP) is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors. We provide technical and policy assistance on regulatory and market policies that promote economic efficiency, environmental protection, system reliability and the fair allocation of system benefits among consumers. We have worked extensively in the US since 1992 and in China since 1999. We added programs and offices in the European Union in 2009 and plan to offer similar services in India in the near future.
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