Public Utility Commission Study

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EXECUTIVE SUMMARY

This Public Utility Commission (PUC) Study examines the regulatory role PUCs play in approving air pollution control modifications by electric utilities. The Study examines the length of time required for relevant PUC approvals, which is important to EPA as the Agency contemplates regulatory timeframes for pending rules affecting power plants. To understand the sphere of influence of the PUC, it is necessary to explore the universe of active regulatory bodies, the history of how electric utilities were regulated and deregulated, and the rate structures central to PUC work. This analysis chose six PUC dockets as case studies to deepen the understanding of how the PUC process shapes utilities' ultimate approach to compliance with environmental regulation.

To provide context for the case studies, this report first explores the boundaries of electricity regulation among the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC) and the PUCs. In general, all of the electricity flowing through interstate commerce is regulated by FERC and its designated authorities. When electricity is distributed to end-use customers in a state, it is regulated by the PUC. In states that have not deregulated their utility sector, the PUC sets the terms of cost recovery for both the electricity generation assets and distribution assets of public utilities through customer rates. In deregulated states, the PUC regulates cost recovery for electric distribution generation assets, but electric generation assets have been "decoupled" and recovery of capital investment is left to the market, not PUCs.

PUC authority over pollution control projects falls into two categories: rate recovery (the recovery of shareholders' investment in the project from ratepayers) and siting review. The traditional mechanism for rate recovery – the general rate case – is almost always undertaken after the project is complete. Pollution control projects are substantial capital investments and can take several years to complete. Waiting for the rate case to determine the overall price tag and whether utility shareholders will recover their investments is not always efficient for shareholders or optimal for ratepayers.

Decreasing the lag time for recouping capital costs is important to utilities' credit ratings and can also reduce the risk of "rate shocks" – large spikes in rates that can occur if recovery is deferred until the next general rate case. To address this dilemma, PUCs may require or allow pre-approvals that address the core prudence issues prior to undertaking the project. Thus, a more expedient rate recovery may be allowed. This is done through cost recovery mechanisms specific to environmental costs or through the use of general recovery mechanisms, such as construction work in progress (CWIP).

Another common PUC pre-approval is the certification of public convenience and necessity (CPCN), which reviews project siting and often includes additional environmental criteria. The certification process is used to ensure that regulated entities are acting in the public interest and adhering to applicable rules and regulations. There are many variations of CPCNs. PUCs that use CPCNs typically require them to be completed prior to plant modification.

Since PUC approvals are common before a control can be fitted to a power plant, we considered the length of these cases. We examined over 100 cases in 10 states. In these cases, utilities sought PUC pre-approvals for a determination on either siting or a cost recovery mechanism. The average time for an approval was seven months, as shown in Figure ES-1. The majority of cases (58 percent) took six months or less; only six cases took over a year. While the PUC process can vary in length, it is clear from the case studies that when deadlines were imposed by the legislature, negotiations – even when complicated – were resolved relatively quickly. Utilities that need to, or choose to, seek pre-approval from a PUC before breaking ground on their compliance strategies for EPA's upcoming regulations should find that the process can usually be completed well within a year based on these data. These timeframes do not reflect time a utility may spend preparing a case before the docket is opened.

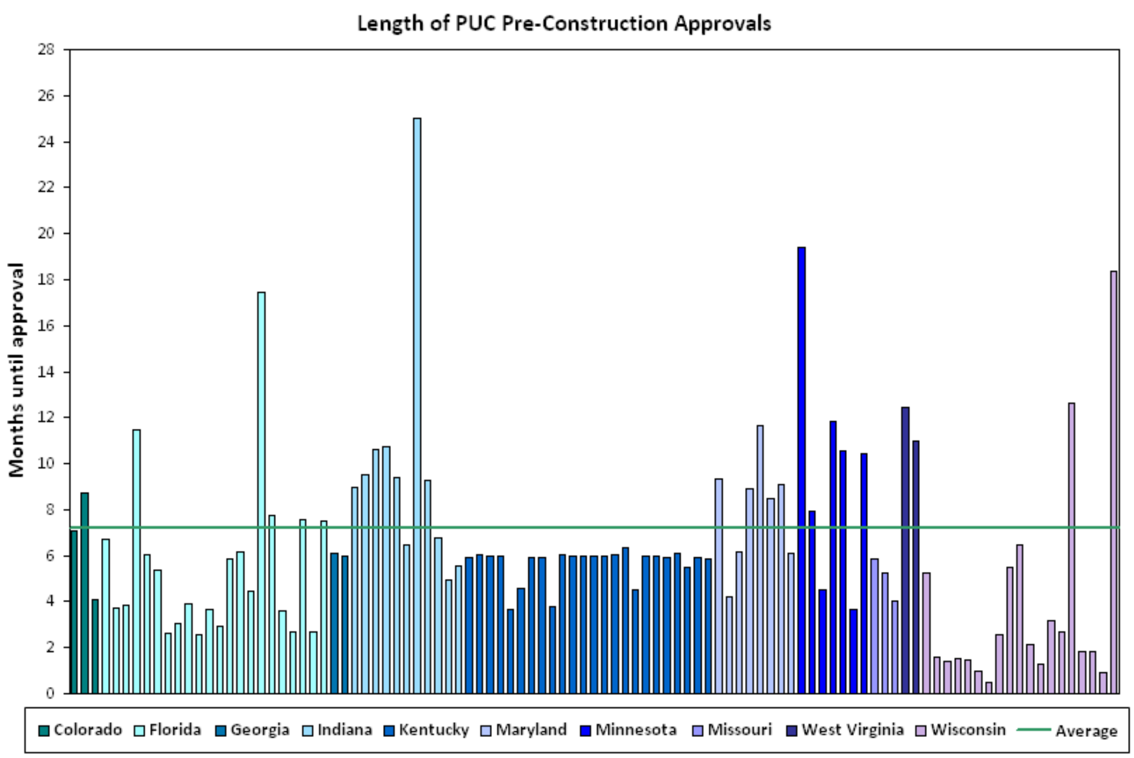

Figure ES-1. Length of PUC Pre-Construction Approvals

The case studies offer insights into the PUC processes covering a wide geographic area. At the core of the PUC process surrounding environmental controls is the determination of which compliance strategy is most advantageous for ratepayers. Since there are often several ways to comply with environmental regulations, the ultimate strategy adopted by a utility can be influenced by the PUC process.

The Colorado case study examines the dynamics that unfold when compliance includes accelerated retirement of multiple coal-fired units and the addition of new natural gas-fired capacity. This case was highly contentious. Intervening stakeholders with varied interests in the electric industry participated, including: coal interests, gas interests, Independent Power Producers (IPPs), environmental groups, and large retail or commercial electricity customers. Because many of the intervenors were linked to national trade associations, the arguments heard in the Colorado case may be echoed in PUCs across the nation as PUCs begin to consider environmental compliance alternatives. The utility was responding to a state law, the Clean Air Clean Jobs Act, designed to help reduce air pollutants and expedite fuel switching from coal to natural gas.[1] Absent that dynamic, it may have been difficult for the PUC to approve such a large volume of fuel switching and construction of new natural gas-fired capacity since the capital cost of adding new gas-fired capacity exceeded the addition of post combustion controls on existing coal-fired generation. The final PUC order in the Colorado case included several modifications to the installation schedule and altered the compliance plan and timing for one of the largest coal units under consideration.

In contrast, Indiana has a state law, the Indiana Coal and Clean Coal Technology statute, explicitly designed to provide incentives for local utilities to continue using Indiana coal by offering favorable financing terms through the PUC. The Indiana case examined a utility's response to EPA's Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). All of the upgrades in the Indiana case were post-combustion controls placed on coal-fired generators. The final PUC order denied the utility's initial proposal by eliminating the mercury controls as too expensive, and substituted the federal CAMR allowance strategy that the D.C. Circuit ultimately eliminated. The PUC also modified the financing terms. The case took well over a year to resolve, during which time there was considerable regulatory uncertainty.

The Maryland case study is a rare example of a CPCN siting approval in a deregulated state. This case was also driven by a state law, the Healthy Air Act. While no rate negotiations took place, the process took about 10 months for siting approval, which included all necessary air permits.

One of the core missions of a PUC in a regulated state is to make determinations regarding cost recovery for environmental expenditures. We examined a variety of innovative rate issues that are of importance to a utility's ability to recoup, in an expedited manner, their costs of complying with EPA's upcoming regulations. The Georgia case represents the first time that projected environmental costs at a Georgia utility were addressed using an accelerated environmental cost recovery mechanism. The Florida case study looks at a PUC denial of a preferred financing approach to new clean generation facilities. The utility was contemplating modernization plans to reduce emissions by shutting down coal and oil units and building state-of-the-art natural gas facilities. The PUC denied the initial proposal, electing to use a future rate case. Lastly, the West Virginia case study examines the use of a unique financing mechanism for utilities, called securitization, in which bonds were created and sold to finance environmental

[1] The law specifically required the utility to examine the replacement of 900 MW of coal-fired generation.

upgrades. Securitization was sought as a way to help reduce the compliance costs for ratepayers and to protect the credit rating of the utility. The docket showcased a significant level of effort on the part of the PUC to develop the knowledge to utilize securitization, which was newly authorized by the legislature.

These examples collectively show that the PUC process can have a substantial effect on compliance planning and the resulting generation fleet. PUC determinations on both rate cases and compliance options appear to have been shaped by the underlying state code or the positions brought forward by intervenors during the process. More often than not, the final order was different from the utility's original proposal. Frequently, the changes were significant, but not fundamental in nature. The intervenors often vigorously contested the amount of capital costs that could be placed in an environmental rider or recovered via CWIP. Among the most seemingly influential groups of intervenors on rate issues were the large industrial or retail customers, such as manufacturing facilities. In the Colorado, Indiana, and Florida cases, the intervenors' detailed scrutiny of cost recovery plans seemed to have an impact on the PUC's rate recovery decision. Nearly all of the case studies were controversial and received local media attention. This is not surprising given the PUC's role as, essentially, the crucible for approving capital-intensive upgrades to be paid for by ratepayers.

For the upcoming suite of new regulations, including Utility Maximum Available Control Technology (MACT), the Clean Air Transport Rule (Transport Rule), Greenhouse Gas Best Available Control Technology (BACT), and Greenhouse Gas New Source Performance Standards (NSPS), the PUCs are likely to be examining a wide range of potentially acceptable mitigation strategies. They might benefit from a best practices document that can identify various approaches, their average costs, and a discussion of the full range of estimated benefits. The National Association of Regulatory Utility Commissioners (NARUC) would be well-suited to collaborate with EPA on such a document and could assist in arranging PUC input and dissemination.

Section I. State Public Utility Commissions and Electricity Sector Regulation: Context, Core Responsibilities and Basic Structure

A. Introduction

This Section provides an overview of the major regulatory agencies overseeing the electric sector, including PUCs, and their lines of responsibility. A brief history of how the electric sector evolved is included. This Section was designed to provide context for Section II, which examines the various instruments that PUCs use in ratemaking and approving major modifications to power plants.

Regulation of utilities was a response to the growth of, and the public's dependence on, railroads and utility companies.[2] These industries held substantial economic power because they were natural monopolies.[3] An unregulated monopoly can dictate prices and extract higher profits at the expense of consumers. To curb this possibility, state and federal governments developed a regulatory apparatus to balance the need for the market to supply the services of natural monopolies while ensuring that these services are priced fairly and provided safely to everyone that requests them. The regulatory apparatus has evolved as the electricity sector has evolved and become deregulated in many states.

Historically, electric utilities were vertically integrated companies, meaning they owned the power generation, transmission grid, and distribution assets (e.g., substations, transformers, and the distribution power lines to end users) in their service territory. These capital-intensive assets create high barriers to entry and give incumbents a natural monopoly over the generation, transmission, and distribution of electricity. Federal and state governments allow these monopolies to exist, but in exchange, the utility agrees to provide reliable and safe service, without discrimination, to any and all customers in its exclusive territories and agrees to have the prices it charges (rates) and the rate of return it earns on investments set by regulators. Regulators, in turn, agree to allow the utility to recover any costs that are "prudently" incurred in order to earn a "fair" return on its investment.

The regulation of the electric industry is split between states and the federal government. Federal agencies, largely the Federal Energy Regulatory Commission (FERC), have jurisdiction over the aspects of the industry that cross state lines – e.g., wholesale power transactions and interstate transmission of power including regional grid reliability. State agencies, which this report refers to collectively as state public utility commissions or PUCs, have jurisdiction over in-

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[2] Eric Filipink. *Serving the Public Interest: Traditional vs. Expansive Utility Regulation*. NRRI Report. October 2, 2009.

[3] A natural monopoly arises when a single supplier has an overwhelming cost advantage over potential competitors, with electric utilities as a classic example.

state power sales and the distribution of power to end users. The following section discusses the role and oversight responsibilities for a traditional PUC.

B. State Public Utility Commissions and the Regulation of Traditional Electric Utilities

The first PUCs were established in New York and Wisconsin in 1907. Since then, every state has adopted some form of state utility regulation. With respect to electricity, the authority of state utility regulatory commissions typically includes:

- Setting the electricity rates that customers are charged;
- Issuing certificates of public convenience and necessity (CPCN) that permit the construction of new power plants and transmission lines and modifications of existing power plants (i.e.,, siting authority);
- Overseeing the distribution of electricity at the retail level;
- Creating standards for safety and quality of service (commonly referred to as reliability);
- Preventing discrimination among customer classes; and
- Providing a public venue for making electric utility decisions.

The majority of state commissioners are appointed to their positions for multi-year terms by their governor or legislature, while commissioners in 13 states are elected. For example, the governors in Minnesota, New Hampshire, and Texas each appoint commissioners to six-year, staggered terms. In each of these states, the governor designates one of the commissioners to serve as chair. In Florida, the commissioners are appointed to four-year terms, while in Wisconsin, commissioners are elected to five-year terms. Figure 1 illustrates which states elect their PUC commissioners and which states appoint them.

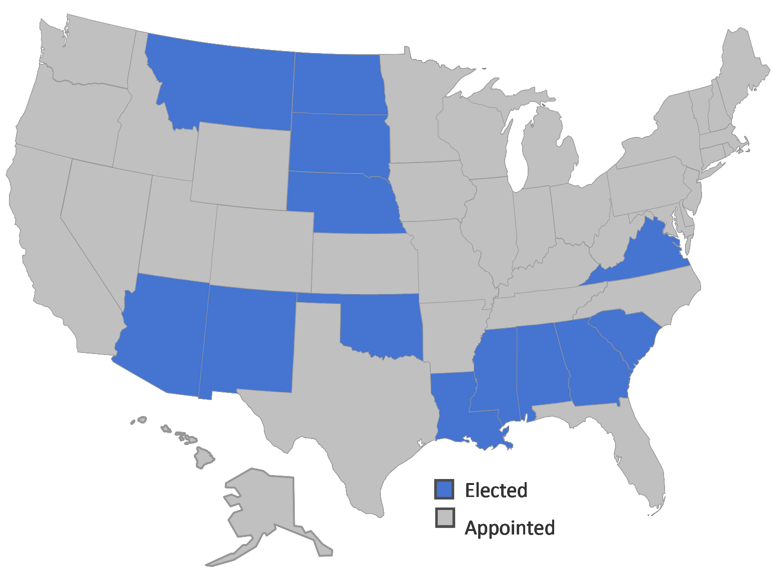

Figure 1. Elected and Appointed PUC Commissioners (Source: NARUC)

C. Federal Regulation: The Federal Energy Regulatory Commission

Today, electricity market oversight resides in multiple places and varies depending on the state. Since the Federal Energy Regulatory Commission (FERC) oversees and enforces electricity markets in every state, we will start this discussion with FERC. FERC is an independent federal agency that regulates the interstate transmission of electricity, natural gas, and oil, among other responsibilities. Five FERC Commissioners are appointed to five-year terms by the President; no more than three Commissioners of the same political party can serve simultaneously. Since FERC is an independent agency, there is no Congressional review of FERC. However, the Government Accounting Office (GAO) has authority to examine FERC's effectiveness. Table 1 outlines general FERC authorities relevant to electricity markets and also specifies where FERC does not have authority.

Table 1. FERC Authorities in Electricity Markets (Source: FERC)

FERC Authority	Issues NOT within FERC Authority
Regulates the transmission and wholesale sales of electricity in interstate commerce. Reviews certain mergers and acquisitions and corporate transactions by electricity companies. Reviews the siting application for electric transmission projects under limited circumstances. Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards. Monitors and investigates energy markets. Enforces FERC regulatory requirements through imposition of civil penalties and other means. Enforces accounting and financial reporting regulations and conduct of regulated companies.	Regulation of retail electricity and natural gas sales to consumers. Approval for the physical construction of electric generation facilities. Regulation of activities of municipal power systems, federal power marketing agencies such as the Tennessee Valley Authority, and most rural electric cooperatives. Regulation of nuclear power plants by the Nuclear Regulatory Commission. Reliability problems related to failures of local distribution facilities. Maintenance, including tree trimmings near local distribution power lines in residential neighborhoods.

Market oversight and reliability enforcement are FERC’s most-recognized functions. FERC provides market oversight by tracking the ten designated electricity markets in the U.S. The geographic outlines of these electric power markets are shown in Figure 2. FERC and its designees analyze and oversee market functions in each of these electricity markets.[4] Reliability oversight will be examined in Subsection E.[5]

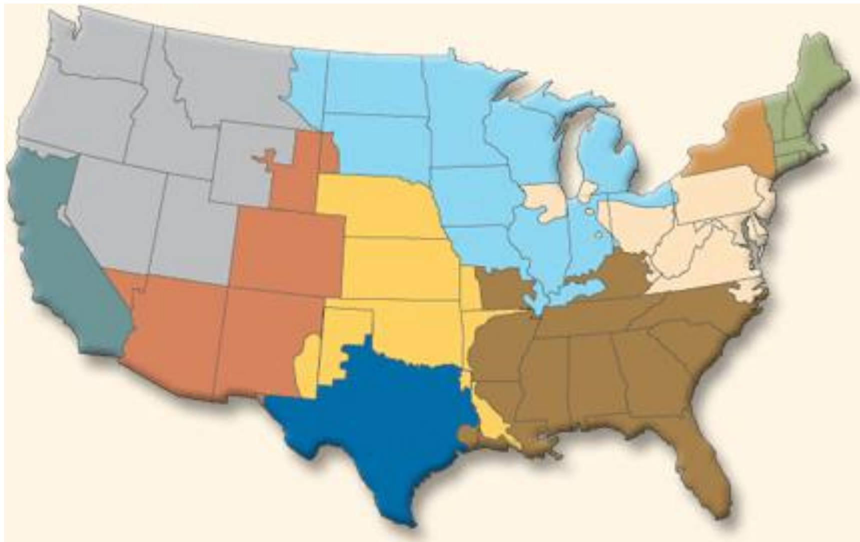

Figure 2. FERC Electric Power Markets (Source: FERC)

D. Deregulation and Redrawing Jurisdictional Lines

Since the early 1980s, nearly half of the states have broken away from the traditional mold by partially deregulating their utilities. The delivery of electricity to consumers and the associated charges remain regulated in all states. In deregulated states, generation and transmission assets have been divested to separate, non-regulated entities. This section will briefly review the federal and state actions that led to deregulation – which shifted the bulk of the oversight responsibilities from the PUCs to FERC and its designated Regional Transmission Organizations (RTOs).

The utility industry began morphing in 1978 when Congress passed the Public Utility Regulatory Policies Act (PURPA), which was designed to promote renewable resources and reduce the use of foreign oil. The Act requires investor-owned utilities to buy electricity from certain non-utility generators at the price the utilities would have had to pay to develop their own resources – their so-called "avoided cost." Competition in the electric industry was further expanded when Congress passed the Energy Policy Act (EPAct) in 1992, which mandated open access to

[4] FERC's analyses for these markets can be found at http://www.ferc.gov/market-oversight/mkt-electric/overview.asp.
[5] Details regarding FERC's electricity oversight functions can be found on FERC's website at http://www.ferc.gov/.

transmission lines. A major effect of that legislation was to allow independent power producers (IPPs) access to transmission lines. In 1996, FERC issued Orders 888 and 889, which further mandated open transmission lines. FERC also created Independent System Operators (ISOs) to ensure transmission access across state lines and mandated the unbundling of utility charges.[6] As transmission lines became more accessible, competition among power producers, both regulated and independent, increased.[7] In this way, FERC Orders 888 and 889 helped spark deregulation, starting in California, as a way to further foster competition in the electricity market.

Deregulation entails the unbundling of vertically integrated electric utilities into separate generation, transmission, and distribution companies. While the distribution portion remains with the regulated utility, transmission and generation assets are either divested entirely or transferred to affiliates of the regulated utility. Thus, the traditional utility would become multiple companies – a deregulated power producer with generation assets, a deregulated transmission company, and a regulated distribution company that delivers electricity to end users (Figure 3). Distribution assets link end users with the transmission grid. The electricity distribution company is often still known as the "utility" and is often the main name seen on electricity bills. Once a traditional utility is broken up, the PUC no longer regulates electricity generation assets. The PUC retains jurisdiction over retail electricity sales to end-use consumers.[8]

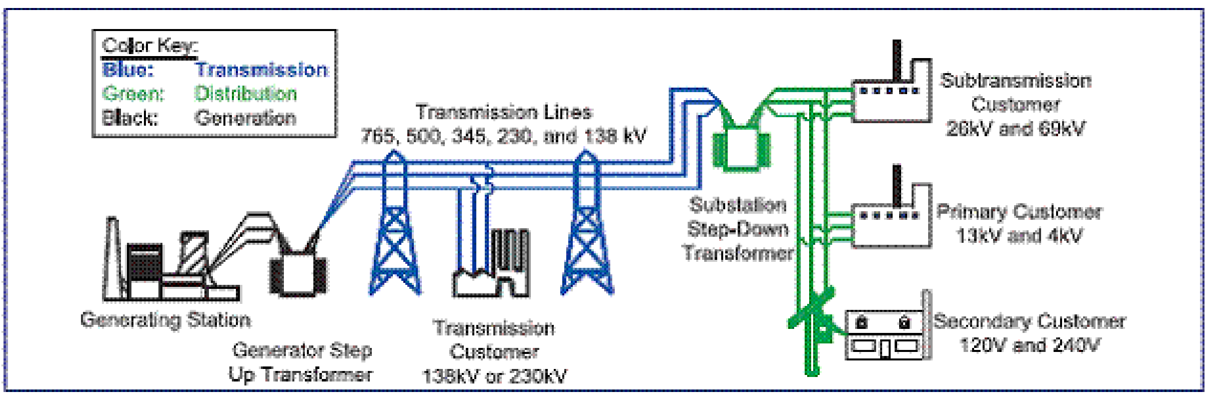

Figure 3. Bulk Power Schematic (Source: NERC)

[6] FERC Order 888 ordered "functional unbundling" of wholesale generation and transmission services, which means that each utility must state separate rates for its wholesale generation, transmission, and ancillary services, and must take transmission of its own wholesale sales and purchases under a single general tariff applicable equally to itself and others.

[7] FERC. *Regional Transmission Organizations (RTO)/Independent System Operators (ISO).* http://www.ferc.gov/industries/electric/indus-act/rto.asp.

[8] The U.S. Supreme Court interpreted the 1935 Federal Power Act as requiring that wholesale sales of electricity are classified as interstate sales subject to federal jurisdiction. *New York et al. v. Federal Energy Regulatory Commission et al.* Certiorari to the United States Court of Appeals for the District of Columbia Circuit No. 00-568. Argued October 3, 2001 - Decided March 4, 2002.

Traditionally, electric utilities owned all components of the electric power system shown in Figure 3. In a deregulated state, the generating stations (black; left of figure), the transmission lines (blue), and the distribution system (green) are split into three separate companies, of which only the distribution system remains regulated by the PUC.

Deregulation has been met with mixed reviews by customers, elected officials, and some industry participants due to higher than expected electricity costs and other complexities. As a result, some deregulated states have begun to investigate the possibility of re-regulation.[9] Figure 4 shows which states have deregulated their electric power industries, as well as several that have suspended further deregulation. In order to manage new independent power producers and new transmission grid users, FERC Order 2000 encouraged the creation of voluntary Regional Transmission Organizations (RTOs) to replace PUC oversight of the transmission grid. The RTOs were created as non-governmental, independent oversight bodies. FERC also delegated market oversight and rate oversight to RTOs where they exist. FERC's general position is that just and reasonable wholesale market costs can best be achieved through greater competition and market forces.[10]

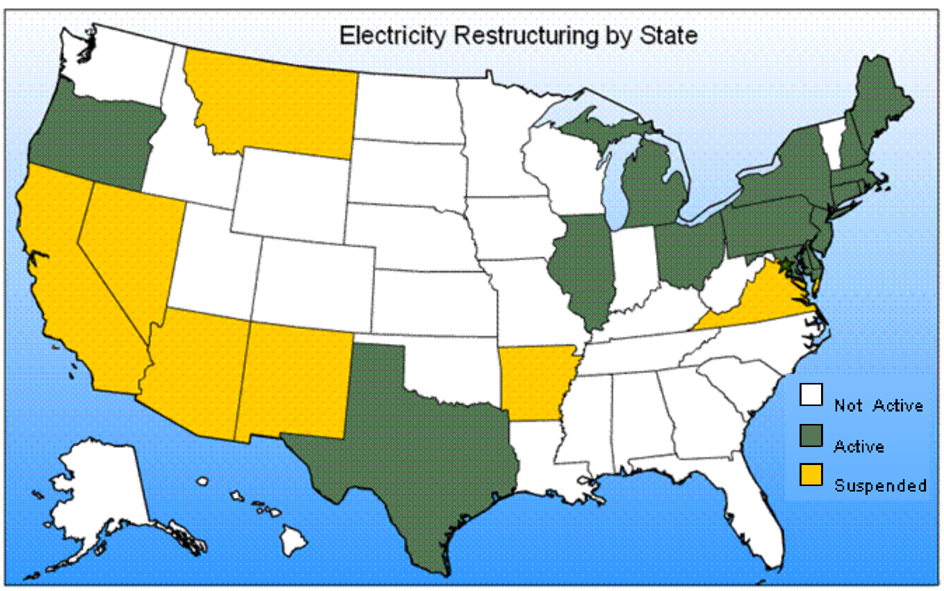

Figure 4. Electricity Restructuring by State (Source: EIA)

The Energy Policy Act of 2005 (EPAct 2005) transformed a number of aspects of electricity industry oversight, in addition to significant mandates in other areas. Under EPAct 2005, FERC gained new authorities to prevent energy market manipulation as well as to manage electric reliability and infrastructure (see the NERC discussion in Section E). To help alleviate congestion

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[9] Tyson Slocum. *The Failure of Deregulation: History, Status, and Needed Reforms*. Public Citizen. March 2007. http://www.ftc.gov/bcp/workshops/energymarkets/background/slocum_dereg.pdf.
[10] U.S. Government Accountability Office. *Electricity Markets: FERC's Role in Protecting Consumers*. June 2003.

on the electricity transmission grid, EPAct 2005 allows FERC to site transmission lines in critical areas, and provides FERC with the authority to override state siting procedures. The Act also requires FERC to review repeal of 1930s-era restrictions on mergers and acquisitions by energy holding companies.

Regulated and Deregulated States

While FERC has some authority in every state, oversight responsibilities vary by state depending on whether electricity generation and transmission are deregulated. For those states that have not deregulated their utilities, PUCs retain traditional oversight functions including rate oversight of retail and wholesale power sales within the state, in-state transmission, and in-state reliability. For those states that have deregulated the electric sector, oversight functions are now distributed over a patchwork of various governmental and independent, non-governmental bodies. These responsibilities in deregulated states are as follows:

- Wholesale power sales and unbundled transmission sales are regulated by FERC, and by extension, the relevant RTOs where applicable.
- Retail rates for end consumers are still regulated by the states, generally through PUCs, but wholesale prices for electricity are set by the market.
- PUCs may still retain some authority over building new generation and making large capital investments, such as installing pollution control technologies or taking generation off line.
- Municipal utilities and electric cooperatives are regulated by local elected officials or boards of directors.

In addition to the regulatory agencies that we have discussed, there are some non-governmental organizations that are active in the PUC arena. Two primary groups are the National Association of Regulatory Utility Commissioners and the National Association of State Utility Consumer Advocates. More detail on these groups is described in Appendix A.

E. Reliability: Responsibilities PUCs, NERC, and FERC

Electricity reliability responsibility encompasses multiple organizations including PUCs, the North American Electric Reliability Corporation (NERC), FERC, and others. FERC created NERC based on its authorization by the 2005 Energy Policy Act, as the electric reliability organization to establish and enforce its reliability standards for the bulk-power system in the U.S. Since electrons cannot be stored and cannot be routed in specific directions (they flow toward the path of least resistance), generation and transmission need to be tightly coordinated, monitored, and controlled on a real time basis to ensure ample and consistent electricity flow. Power supply and demand must be balanced with ample reserve capacity along the interconnected grid. NERC is the organization designated by FERC to develop and enforce a portfolio of standards and regulations to ensure the reliability of electricity in North America.[11]

NERC sets and enforces a suite of reliability standards, such as infrastructure coordination, maintenance, and protection standards, for the bulk power system. The bulk power system refers to power generators, transmission lines, and interconnections among neighboring transmissions systems that generate and transmit electricity over high-voltage transmission lines. It does not include the distribution system. PUCs are the organizations that generally monitor and enforce reliability issues in the distribution grid, where electricity is delivered to end users.

The reliability standards proposed by NERC must be approved by FERC to become legally binding.[12] NERC works with eight regional entities to develop, enforce, and monitor compliance with reliability standards. The eight regional entities carry out compliance enforcement activities on behalf of NERC.[13] The regional entities are shown in Figure 5, and include:

- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool Regional Entity (SPP RE)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

Figure 5 also illustrates the states these entities encompass. Members of the regional entities come from every aspect of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. Since each region has unique

[11] NERC Website. Accessed November 2010. http://www.nerc.com/.
[12] NERC. *Company Overview*. Accessed November 2010, http://www.nerc.com/page.php?cid=1|7.
[13] NERC. *Compliance: Regional Programs*. Accessed November 2010. http://www.nerc.com/page.php?cid=3|23.

generating assets and issues, there are regional reliability standards for each region. NERC oversees these programs for consistency and fairness.

NERC works with and applies standards to a whole variety of electricity groups in addition to the eight regional entities described above. For example, NERC groups large bulk power systems, like the one shown in Figure 3, together as "Balancing Authorities." These Balancing Authorities are responsible for meeting many of NERC's reliability standards for the bulk power system, including the real-time balance of supply and demand for electricity. There are currently 134 Balancing Authorities in the U.S. that operate within Balancing Authority Areas. These areas are not spread evenly among the regional entities, as shown in Figure 5.

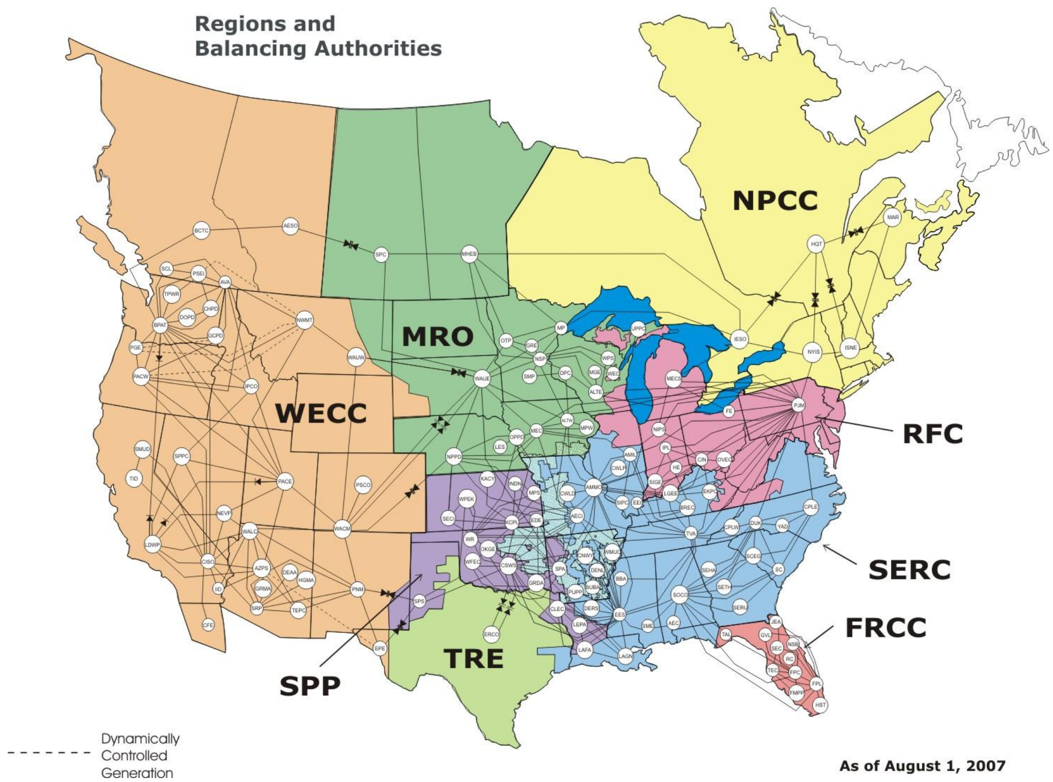

Figure 5 Regional Entities and Balancing Authorities

NERC has developed an array of reliability standards that affect different entities[14] depending on the nature and scope of the requirements.[15] Some of NERC's standards pertain to Balancing Authorities, or Reliability Coordinators, and others pertain to Transmission Operators. To illustrate the extent of reliability standards and the various entities that meet these standards, Appendix B includes a subset of NERC's reliability standards. Despite the volumes of reliability

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[14] NERC. *Reliability Standards for the Bulk Electric System of North America*. Accessed November 2010. http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf.

[15] Depending on the nature and scope of the standard, it could apply to all or some of the following entities: Reliability Coordinator, Balancing Authority, Interchange Authority, Transmission Service Provider, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, Load Serving Entity, NERC, or Regional Entity.

standards that exist, capacity reserve is one of the most often discussed reliability metrics. Typically, the capacity reserve is set between 12 and 15 percent and is enforced by the regional entities.

In addition to developing and seeing to the enforcement of reliability standards, NERC also compiles annual reliability assessments of the bulk power system. These include long-term reliability assessments as well as summer and winter assessments. In addition to these annual and regular assessments, NERC also issues special assessments as needed. A timely example is NERC's special assessment of EPA's upcoming regulations impacting the power sector. In that special report, NERC examined the potential reduction in generation that would result from the retirement of specific coal-fired units in response to the Utility Maximum Achievable Control Technology (MACT), the Clean Air Transport Rule (Transport Rule), regulation of Coal Combustion Residuals (CCR), and the Clean Water Act Section 316(b) regulating Cooling Water Intake Structures.[16]

[16] NERC. *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. EPA Regulations*. October 2010. http://www.nerc.com/files/EPA_Scenario_Final.pdf.

Section II. State Regulatory Commissions and Pollution Control Strategies: Sources of Authority and Types of Regulatory Approvals

Two functions of PUCs, ratemaking and siting authority, provide the most common jurisdictional hooks over pollution control strategies. Ratemaking comes into play in traditionally regulated states, where generation assets are still regulated, when the utility seeks to recover the costs of a project. This is traditionally done through a general rate case in which cost recovery is sought after the investment is made and the project is in service. The PUC determines whether the rate increase request should be granted, denied, or revised.

Rate cases are an after-the-fact review, which can create a lengthy "regulatory lag" between shareholders' substantial investment and the time when the rate increase by the PUC is approved and shareholders can begin to see a return. To address regulatory lag, PUCs often have a number of additional tools at their disposal that can be utilized to increase the certainty of a project's ultimate approval and to accelerate the cost recovery process. These tools include siting certification, a process by which the PUC ensures that major utility decisions such as investment in new power plants, construction projects, or pollution control installations, are necessary and in the public interest. Certification can take place in both regulated and deregulated states, with deregulated states focusing on issues such as reliability and environmental issues and leaving issues such as need and cost largely to the market.

A. The Ratemaking Process and Cost Recovery for Pollution Control Projects

Ratemaking Overview

The ratemaking process is a complicated, multi-step procedure that begins when the utility files a rate case with the PUC to recover new costs from major new infrastructure projects (e.g., a pollution control retrofit or plant fuel conversion) or an unexpected increase in operating or maintenance expenses. The two basic elements in the ratemaking process are (1) establishing the revenue requirement and (2) setting the rates that customers must pay (rate design).

Step 1. Establishing the Revenue Requirement. The revenue requirement is the total annual revenue a utility requires to recover all of the costs of serving its customers, including a fair return on shareholders' investment of capital. In simple form, the revenue requirement consists of:

Revenue Requirement = Utility Expenses + (Rate of Return * Rate Base)

In this formula, the money spent by a utility falls into two categories, expenses (such as the cost of procuring fuel for a power plant) and capital investments, such as pollution control equipment. The rate base is the aggregate of shareholders' outstanding capital investments. The rate of return on the rate base is determined by the utility's cost of capital – the fair market return for shareholders' investment. The rate of return is allowed, but not guaranteed. If costs exceed the expectations of the rate case, the shareholders may earn a lower return.

Step 2. Setting the Rates (Rate Design). This process typically starts by apportioning relative cost burdens among different customer classes (e.g., residential, commercial, and industrial) and then designing a rate structure for each class that will result in meeting the revenue requirement. This includes dividing the rates into different schedules or charges (e.g., basic charge, energy charge (per kWh), and a demand charge (per kW)). An energy charge is similar to a metered use rate, while the demand charge is based on projected capacity needed to meet the customers' peak demand.

Cost Recovery and the Rate Case

Ratemaking is a dynamic process, because the markets and the conditions in which the utilities operate and to which they must respond to are constantly changing. Rates are set to meet the conditions prevailing at the time and need to be reset as conditions change. Pollution controls provide an example. As environmental requirements change, utilities must invest in the equipment and strategies needed for compliance, which may require substantial capital outlays. If such expenses were not contemplated in the previous rate case, there will be a "revenue deficiency," meaning that the revenue generated through the current rates will not be sufficient to meet the current revenue requirement. As a result, shareholders will, in effect, be receiving less than their approved fair rate of return until the deficiency is remedied.[17]

Filing a rate case is the traditional method for curing a revenue deficiency. Historically, the capital investment aspects of the rate case are reviewed after-the-fact, i.e., the investment has been made and the project entered into service before the case is filed. The PUC determines whether the investment was prudent. The prudence review is based on the conditions prevailing when the decisions were made and often includes questions such as:

- Are the costs incurred to meet the needs of customers?
- Are the costs necessary to provide adequate service?
- Are the costs reasonable?
- Was the technology selection prudent?
- Is the plant investment used and useful?
- Will ratepayers derive a benefit?
- Is the capital investment consistent with any commission mandated integrated resource plan?[18]

All prudent aspects of the investment will be added to the rate base, while costs deemed imprudent will be disallowed and borne by shareholders.

[17] When utilities seek cost recovery, they are seeking the recovery of two different costs: the cost of capital (i.e. a financial return on their shareholders' investment) and the capital itself (return of shareholders' capital over time).
[18] Lowell E. Alt, Jr. *Energy Utility Rate Setting*. 2006.

As a general rule, capital investment in pollution controls that are required for compliance will be deemed a prudent investment. For example, as stated by the Alabama Public Service Commission in a case establishing an environmental compliance cost recovery mechanism:

> [Environmental compliance costs] by definition are the product of governmental mandates establishing environmental requirements with which Alabama Power, by law, must comply. These are not costs that Alabama Power can simply choose not to incur, which in turn strongly supports a presumption that they are prudent expenditures.[19]

However, there are often nuances to this general rule that make approval less certain. For example, multiple options could be available to reach compliance, each with different costs and benefits. In addition, regulatory burdens may be uncertain or undefined, potentially making early compliance strategies more of a risk. In another possible scenario, aspects of a nominally prudent investment could be deemed imprudent and disallowed (e.g., because of inadequate cost controls). For example, a case in Indiana rejected activated carbon injection (ACI) technology to reduce mercury emissions, based on the assertion that there were numerous mercury emission control technologies under development at the time that could prove to be more economical and efficient. For more details see Section IV, Indiana Case Study.

Rate Case Mechanics: An Overview of PUC Procedure[20]

Although the process for rate cases, as well as other PUC cases, varies from state to state, it typically includes the following:

- **Application**. The utility generally initiates a rate case by filing an application or petition with the PUC. The application will include the requested changes and supporting financial data and may include supporting written testimony. The application may also request an interim rate change in order to reduce the impact of the regulatory lag between filing and the date that new rates go into effect.

- **Intervention**. Parties affected or otherwise interested in the case will have an opportunity to enter into the case. The rules governing intervention and the role that various intervenors are permitted to play (from active to passive) vary by state.

- **Schedul**e. The PUC or the parties will develop a schedule that include dates for filing of testimony, cutoff dates for intervention, dates for public meetings regarding the case, discovery deadlines, dates for hearings, and dates for filing of briefs.

[19] Alabama PSC Docket Nos. 18117 and 18416, Order, Petition to amend Rate CNP (Certified New Plant) to provide for the recovery of costs incurred to comply with environmental mandates. October 29, 2004.
[20] For additional detail, see Lowell E. Alt, Jr. *Energy Utility Rate Setting*. 2006. pp 99-108.

- **Audits**. State regulatory staff and parties audit the utility's books and records to determine compliance with statutes, tariffs, commission rules, and orders and to determine the reasonableness and prudence of the utility's expenses and investments.

- **Discovery**. Discovery is the process by which parties obtain information from each other through written requests and answers. Discovery can be quite extensive, generating possibly thousands of data requests in a large general rate case, and often spawning disputes that must be resolved by the PUC and the intervening parties before moving the case forward.

- **Written Testimony**. Testimony in the rate case is both written and oral. The utility typically files written testimony as its direct case. This includes the testimony, supporting data, and exhibits necessary to explain and support the utility's revenue requirement request. Testimony from other parties follows to rebut specific aspects of the utility's direct case.

- **Hearings**. Oral testimony is provided at public hearings, usually by the same people providing the written testimony, providing the other parties an opportunity to cross-examine witnesses. It is not uncommon for hearings to be opened to the public to include questions and comments from the local community as well.

- **Briefing and Orders**. Briefs are filed by each party summarizing its position and articulating its key arguments. After the briefing is complete, negotiation between the utility and intervenors often helps defuse debates. The PUC renders a decision and order on the case.

- **Approval**. Once a rate case is approved, the new rates are put into effect and the changes are reflected in customer's bills.

B. Beyond the Rate Case: Tools to Enhance the Chances and Timing of Cost Recovery

Traditionally, cost recovery is approved after the project is complete, through a rate case. However, cost recovery via an after-the-fact rate case may put utility shareholders at risk of an incomplete recovery, can affect the utility's creditworthiness, and may put consumers at risk of periodic "rate shocks" as several large-cost items accrued over a period of time are rolled into a single rate adjustment.

Over the past two decades, PUCs have addressed this dynamic by developing mechanisms that (1) provide more certainty that the rate case will have a favorable outcome through some form of pre-approval, and (2) provide some form of early cost recovery without resorting to a full rate case in order to reduce regulatory lag. In the context of pollution control projects, these mechanisms are often combined as a way to move the projects forward expeditiously while reducing overall risk to utilities and ratepayers.

Regulatory Pre-Approvals

State PUCs can provide a number of pre-approvals for pollution control projects. The intent of the pre-approval is to assess the prudence of the pollution control strategy before construction begins by addressing issues such as the need for pollution controls; selection of alternative, cost-effective strategies and technologies; and the range of acceptable costs. While this process addresses many critical aspects of prudence review up front, in most cases it does not guarantee full cost recovery – the project will still be reviewed on a periodic basis or upon completion to ensure that costs remain reasonable and controlled. This section provides an overview of a number of pre-approvals that are utilized for pollution control strategies.

Certification

The certification process is utilized by PUCs to ensure that regulated entities are acting in the public interest and adhering to applicable rules and regulations. In the context of electricity generation, certification is often used as a siting tool to screen whether a proposed project is needed and whether it will serve the public interest – e.g., if the project will meet regulatory requirements, enhance reliability and safety, and provide low-cost electricity to ratepayers. Certification is most commonly used to review proposals for new power plants, but in many states it also applies to other major financial commitments, such as pollution control projects. Often the certification is in the form of a Certificate of Public Convenience and Necessity (CPCN).

In thirty states, the certification process includes consideration of environmental protection. This process may occur through a full-blown regulatory proceeding, or by acknowledging that another state agency with expertise on the issues (e.g., state environmental and public health agencies) has undertaken an appropriate review that will be incorporated into the certificate.[21] For example, Kentucky requires new generation facilities to be certified by the PUC. As part of the process, the project is reviewed by the state's Environmental Cabinet. PUCs may also have a role in reviewing compliance with federal environmental standards. Under Michigan law, for example, the Michigan Commission must ensure that all electrical power generating facilities in the state comply with all federal rules, regulations, and mercury emissions standards.[22]

Because the certification inquiry often goes beyond rates and recovery, it may be utilized in both regulated and deregulated states. In regulated states, the certification can act as a pre-approval for rate recovery by addressing a number of prudence issues, such as need for the controls, technology selection, and cost. In deregulated states, rate recovery is not on the table. Consequently, issues such as cost tend to be minimized (since the market is expected to dictate whether these are reasonable), and the inquiry may focus on issues such as reliability or other factors. To the extent that certification review does include environmental issues, PUCs may defer to the expertise of state environmental agencies that are also reviewing the project. The

[21] Michael Dworkin, et al. *The Environmental Duties of Public Utility Commissions*. Vermont Journal of Environmental Law. 2006.
[22] *Id*.

cases studies in Section IV of Maryland and Indiana provide examples of the certification process in the deregulated and the regulated contexts.

Resource Plans

Integrated resource plans (IRPs) are comprehensive planning tools used by utilities and other energy planners to design reliable and least-cost approaches to providing electric service while addressing the risks and uncertainties in the electric utility business. IRPs are usually developed periodically through a public process that includes PUC staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders. The plans include an assessment of both supply-side and demand-side alternatives, a long-run analysis of alternatives, a short-term action plan, full assessment of all risks associated with each alternative, and analysis of external costs such as environmental costs and how those costs may affect resource choices. The value of a resource plan as a pre-approval depends on the extent of the PUCs involvement in developing the plan, whether the PUC provides a formal approval of the plan and the extent to which the pollution control strategy adheres to the plan in practice.

Comprehensive Environmental Compliance Plans

Legislatures in some states have mandated that utilities provide plans demonstrating how the utilities will meet federal and state air quality compliance obligations. These requirements are often coupled with mechanisms for cost recovery. For example, Colorado passed legislation in 2009 that required “a coordinated plan of emission reductions” from coal-fired power plants that “will enable Colorado rate-regulated utilities to meet the requirements of the federal Clean Air Act and protect public health and the environment at a lower cost than a piecemeal approach.”[23] The plan will include the utility’s compliance strategy for all of its coal-fired power plants and provide a method for cost recovery. The process for developing the plans is shared by the Colorado PUC and the state’s air quality agency, providing multiple points for public review and participation. Once the PUC and the state air quality agency approve the plan, they must be ratified by the legislature. This comprehensive process essentially guarantees cost-recovery for the approved plan as long as actual costs incurred remain within a reasonable range of the projections. This process is described in more detail in Section IV, Colorado Case Study.

Project Specific Pre-Approvals

States may also use a more targeted approach by allowing pre-approvals for pollution control strategies at specific power plants. For example, Minnesota passed legislation in May 2010 allowing utilities to apply for an “Advance Determination of Prudence.”[24] Under this process, a utility may seek advance prudence review from the PUC prior to making equipment upgrades required to comply with state and federal air quality standards. The utility must provide the

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[23] State of Colorado. House of Representatives. *House Bill 10-1365*. 67th General Assembly. 2010. http://www.leg.state.co.us/clics/clics2010a/csl.nsf/fsbillcont/0CA296732C8CEF4D872576E400641B74?Open&file=1365_ren.pdf.

[24] 2010 Session Laws Chapter No. 373. May 20, 2010.

PUC with a description of the project, an implementation schedule, a cost estimate, and a description of the utility's efforts to ensure the lowest reasonable costs. The utility may begin recovering the upgrade costs in the next approved rate case after the advance determination of prudence. The goal of the program, which is in effect through 2015, is to give lenders comfort that the utility has the PUC's blessing to proceed with the mandated upgrades. Without it, utilities might be denied a loan or be required to pay a higher interest rate, leading to higher costs and resulting in higher rates to consumers.

Legislatively Mandated Pollution Controls

Other states have been more prescriptive by mandating specific forms of pollution controls either generally or for specific power plants. For example, in New Hampshire the state legislature developed special legislation for non-divested assets – generation assets that had not yet been sold as part of the state's deregulation program. The legislature provided a general pre-approval where the utility would be allowed to modify or retire a unit if the PUC finds "it is in the public interest of retail customers of [the utility] to do so, and provides for the cost recovery of such modification or retirement."[25] However, the legislature also made a special finding that a wet scrubber at one plant was in the public interest, providing an incentive to add a wet scrubber at that site.

Environmental Cost Recovery Mechanisms

Many states allow utilities to recover costs through a periodic adjustment mechanism instead of a general rate case. These rate mechanisms adjust automatically to changes in the utility's underlying related costs. These cost recovery mechanisms go by different names, but are generally referred to as "Automatic Adjustment Clauses" or AACs.[26]

AACs are usually used to address volatile commodity costs arising in wholesale markets, such as fuel and purchased power costs. Such costs are outside the control of the utility and, therefore, the prudence issues surrounding cost increases are narrower. However, capital costs associated with mandatory investments, such as the pollution control investments, are increasingly being recovered through some form of AAC. As noted above, utilities have little discretion in deciding whether they will comply with regulatory mandates, so automatic recovery in some form is often allowed because the risk of imprudence is lower. At the same time, improving the certainty surrounding recovery will lower the costs of financing the project by protecting the debt ratings and creditworthiness of the utility. However, like pre-approvals, AACs do not provide complete certainty – the investments are still subject to periodic prudence review audits.

A 2006 survey performed by The Brattle Group found that, of the 27 traditionally regulated states that currently have AACs, 11 states allow rate adjustments for environmental capital costs

[25] RSA 125-O:11, VI

[26] The Brattle Group. *Electric Utility Automatic Adjustment Clauses: Benefits and Design Considerations*. Prepared for the Edison Electric Institute. November 2006.

and for the cost of emissions allowances.[27] These programs go by various names – air quality improvement rider, environmental improvement rider, energy cost adjustment, environmental cost recovery surcharge, etc., but they tend to have the same basic features: a routine, simplified process for recovering environmental costs, by adding them to the rate base or setting up a separate surcharge for direct recovery of the costs, that does not require prior review and approval but does include after-the-fact auditing and a process for "truing-up" expenses on a regular basis.

Alabama Power's environmental recovery mechanism provides an example. In October 2004, the PUC approved a dedicated recovery mechanism for environmental control compliance costs.[28] The PUC decided not to require a pre-approval or other prudence review – these decisions were left to the state environmental agency, the utility and its parent company. The utility is required to provide an environmental control plan to inform the PUC and stakeholders of its plans and projected costs, but the plan is not subject to a formal process. With these prudence issues addressed, the Alabama process focuses on cost recovery. The utility estimates new environmental costs each year and Tariff CNP, one of the charges paid by each rate class, is adjusted to reflect the new costs. This includes an annual "true-up" process where the actual costs from the previous year are compared to the projections and the difference applied to the current year adjustment.

CWIP

In addition to environment specific mechanisms, some utilities in certain states can also take advantage of general capital cost recovery mechanisms, such as "construction work in progress" or CWIP. A number of states have adopted this mechanism to address the often substantial regulatory lag created by major construction projects where significant costs can accrue over several years before the project is placed in service and eligible for rate recovery. The Indiana case study provides an example of how CWIP can be used with pre-approvals to increase the certainty and pace of rate recovery.

Securitization

Securitization is a financial tool that essentially packages bonds backed by fairly certain recovery and sells the bonds on the market as a highly rated security. Securitization can be used by utilities to fund pollution control projects by using ratepayer funds as the source for paying the return on the investment. This is typically done by placing a special surcharge on customer bills dedicated to payment on the bonds. These customer-backed bonds give investors confidence that that their investment will have a very high probability of being paid back. Because the risk is low, the bonds will be highly rated and the utility will get a lower interest rate than it would normally receive by financing the investments through traditional debt finance, ultimately

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[27] *Id*.

[28] Docket Nos. 18117 and 18416, Order, Petition to amend Rate CNP (Certified New Plant) to provide for the recovery of costs incurred to comply with environmental mandates. October 29, 2004.

saving ratepayers money.[29] An example of securitization can be found in Section IV, the West Virginia case study.

[29] Edison Electric Institute. *State Regulatory Update: Rate Impact Mitigation Measures*. June 2010. http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/rate_impact_mitigation.pdf.

SECTION III. TIMING ANALYSIS

Discussion of compliance time is often focused around the amount of time required to make the physical modifications to install pollution reduction equipment, but in many states, certifications and approvals are required before a plant owner can begin construction. In the context of this PUC Study, it is worth examining the time requirements of the various PUC processes as they relate to add-on control installation. However, in some states, no pre-approval is needed and the PUC only reviews the project formally when the rate case is filed.

A. Ratemaking and Regulatory Lag Time

The Edison Electric Institute (EEI) tracks the PUC processes related to its members, investor-owned utilities. As part of this service, EEI tracks regulatory lag time, which they define as the time between a rate case filing and a decision by the PUC. According to EEI's data, from Q1 1990 through Q3 2010, the lag time for rate cases averaged around 10 months.[30] Figure 6 tracks the regulatory lag time for rate cases over the past two decades. Generally, rate cases come to the PUC after any equipment included in a rate request has been installed, and these cases do not usually include any type of pre-approval for a pollution control project. The mid-1990s and early 2000s reflect a high volatility in lag time during the years of frequent deregulation and restructuring.

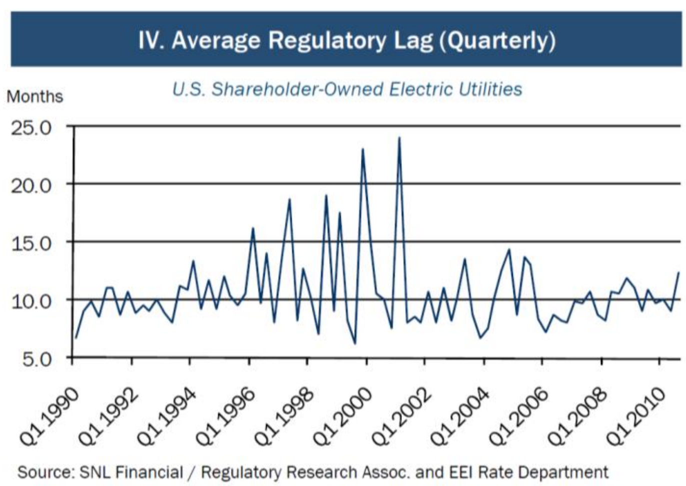

Figure 6. EEI Lag Time Analysis 1990-2010

[30] Edison Electric Institute. *Rate Case Summary: Q3 2010 Financial Update*. 2010. http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Documents/2010_Q3_Rate_Case_Summary_Final.pdf.

B. Pre-Construction PUC Approval Times

While the regulatory lag time for rate requests is illuminating, there are often other mandatory or optional PUC approval processes conducted before a project has begun construction. Along with permits from the state's Department of Environmental Protection, utilities or generation owners are in some cases required to obtain a construction approval, CPCN, or other certificate from the PUC. Optional processes also exist in some states in which utilities can apply for assurances of cost recovery, ratemaking treatment, or accounting treatment for pollution control projects before beginning construction, as discussed in Section II. For example, utilities may be able to apply for use of an environmental surcharge to fund the capital costs of future projects, for permission to include their construction costs in rates before the project is completed (CWIP), for an advance determination that the project is "prudent" and will be eligible for cost recovery, or to allow deferred accounting treatment for the costs of a project. This type of pre-approval is favored by utilities because it provides more financial certainty before embarking on an expensive project. The process of obtaining pre-approvals from the PUC has important implications for compliance with environmental regulations. If the approval process before construction commences is lengthy, it has the potential to delay compliance. Even if an approval is not mandated, utilities may find it financially necessary to avail themselves of the optional pre-approval processes before beginning a pollution control project.

Methods

To better understand the time required to obtain approvals needed before breaking ground on pollution control modifications, this analysis examined pollution control retrofits at existing coal plants. Using a database of scrubber installations assembled from EPA and proprietary data (Table 2), we identified the states that had one or more scrubber installations in 2010, and selected those states for analysis. The states were Alabama, Florida, Georgia, Illinois, Indiana, Kentucky, Maryland, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Virginia, West Virginia, and Wisconsin.[31] Data from Colorado were also included because it was one of the six case studies.

Because the names of approval processes vary from state to state, and docketing systems are often difficult to navigate, personal contact with PUC staff was sometimes necessary to obtain information about any pre-approvals required for pollution control projects in the state and to identify docket numbers of specific cases involving these approvals.

[31] Though it had nine scrubber upgrades in 2010, Tennessee was excluded from analysis because all of the upgrades were at Tennessee Valley Authority plants. TVA is not regulated by the Tennessee Regulatory Authority.

Table 2. Scrubber Installations by Year

State	Year Scrubber Came Online									No. of Scrubbers
	2004	2005	2006	2007	2008	2009	2010	2011	2012	
Alabama				3	1	1	4	1		10
Arizona					1	1				2
Colorado					2					2
Florida						4	1			5
Georgia					7	2	1	2		12
Illinois							2	3		5
Indiana	2		2	2	2	2	7			17
Iowa				2	1					3
Kentucky		3	1	1	1	2	3			11
Maryland						7	2			9
Massachusetts			1		2					3
Michigan						2				2
Minnesota				1	3		1			5
Missouri							2			2
New Jersey							2	1		3
New York			1				5			6
North Carolina		1	3	5	5	7	1	1	1	24
North Dakota								1		1
Ohio				1	6	4	8	3		22
Pennsylvania	2				2	8	5			17
South Carolina			2	2	3					7
Tennessee						1	9	4		14
Texas						2				2
Utah			1							1
Virginia					1	5	3			9
West Virginia			3	2	1	1	1			8
Wisconsin			1	1			1			3
Wyoming									1	1
No. of Scrubbers	4	4	15	20	38	49	58	16	2	206

This analysis focused specifically on cases dealing with add-on emissions controls for NO_X, SO_2, mercury, and particulate matter. Other types of environmental projects were included only if they were included in the same filing as an add-on emissions control. Efforts were made to include all cases involving pre-approvals for add-on emissions controls that concluded prior to December 31, 2010, and were available in a state's online docketing system.

For the states examined, we provide a summary of the type of pre-approvals allowed or required for pollution control projects, as well as an analysis of the time between initiation of a case and final action. The time taken for construction planning and assessment, or the time required to obtain permits from other agencies, are not included in this analysis; it solely reflects the time taken by the PUC to review and approve a case prior to construction.

Results

PUCs in deregulated states, because they do not have jurisdiction over the generation component of electric rates, cannot provide any pre-approval processes for cost recovery of emissions control projects; nor, for the most part, do they require construction approvals. For example, Pennsylvania does not require or allow any pre-approvals, nor does the partially deregulated Ohio. Maryland is an exception; although deregulated, it requires generation owners to obtain a CPCN before constructing any emissions controls.

Regulated states, on the other hand, take a wide variety of approaches to certifying emissions control projects. Some states, such as Indiana and Florida, have laws specifically authorizing or even requiring certain kinds of pre-construction cost recovery for emissions control projects. Others, such as Missouri, leave it up to utilities and the PUC to decide the best approach. Table 3 summarizes the different states' policies, and lists the average length of pre-construction PUC cases.

Table 3. Summary of Timing Analysis Results

	Electricity Regulation	**Pre-Construction Certificate**	**Pre-Approval of Cost Recovery**[32]	**Average Length of Pre-Approval Case**
Alabama	Regulated	Not required	Allowed	N/A
Colorado	Regulated	Not required	Allowed	6.64
Florida	Regulated	Not required	Required	5.53
Georgia	Regulated	Not required	Allowed	6.02
Illinois	Deregulated	Not required	Not allowed	N/A
Indiana	Regulated	Required	Allowed	9.75
Kentucky	Regulated	Required	Allowed	5.65
Maryland	Deregulated	Required	Not allowed	8.00
Minnesota	Regulated	Not required	Allowed	9.77
Missouri	Regulated	Not required	Allowed (limited)	5.05
New Jersey	Deregulated	Not required	Not allowed	N/A
New York	Deregulated	Not required	Not allowed	N/A
North Carolina	Regulated	Not required	Not allowed	N/A
Ohio	Partially deregulated	Not required	Not allowed	N/A
Pennsylvania	Deregulated	Not required	Not allowed	N/A
Virginia	Regulated	Not required	Not allowed	N/A
West Virginia	Regulated	Required in some circumstances	Allowed	11.71
Wisconsin	Regulated	Required	Not allowed	3.79
All states				**7.19***

* This is the average of each individual state's average, not the average of all cases, in order not to weight states with a large number of cases more heavily. The average of all cases was 6.33 months, and the median was 5.95 months.

[32] See Appendix C for a more detailed explanation of individual state policies, and reasons for excluding certain states from analysis.

In several states, including Ohio, North Carolina, Pennsylvania, and Virginia, no approvals are required or allowed by the PUC prior to installation of control technologies. These states were not included in the timing analysis. The absence of these approvals, however, suggests that utilities in these states have fewer hurdles prior to construction and, therefore, would be able to begin installation of control technologies more quickly once all required environmental permits have been received. Most regulated states either require or allow an approval (either a CPCN or an authorization pertaining to financial terms) before construction for control technologies commences. Figure 7 shows the length of every case examined in the states that require or allow a PUC approval before an owner may install a control technology on a facility. The PUC process times in some states, like Kentucky, were very consistent. This is due to the fact that there is a statute in Kentucky that requires the PUC to process environmental plans within six months. Other states, such as Wisconsin and Florida, appeared to have much more variable process times. Drawing conclusions from these data is difficult, given that they compare different types of cases both between and within states.

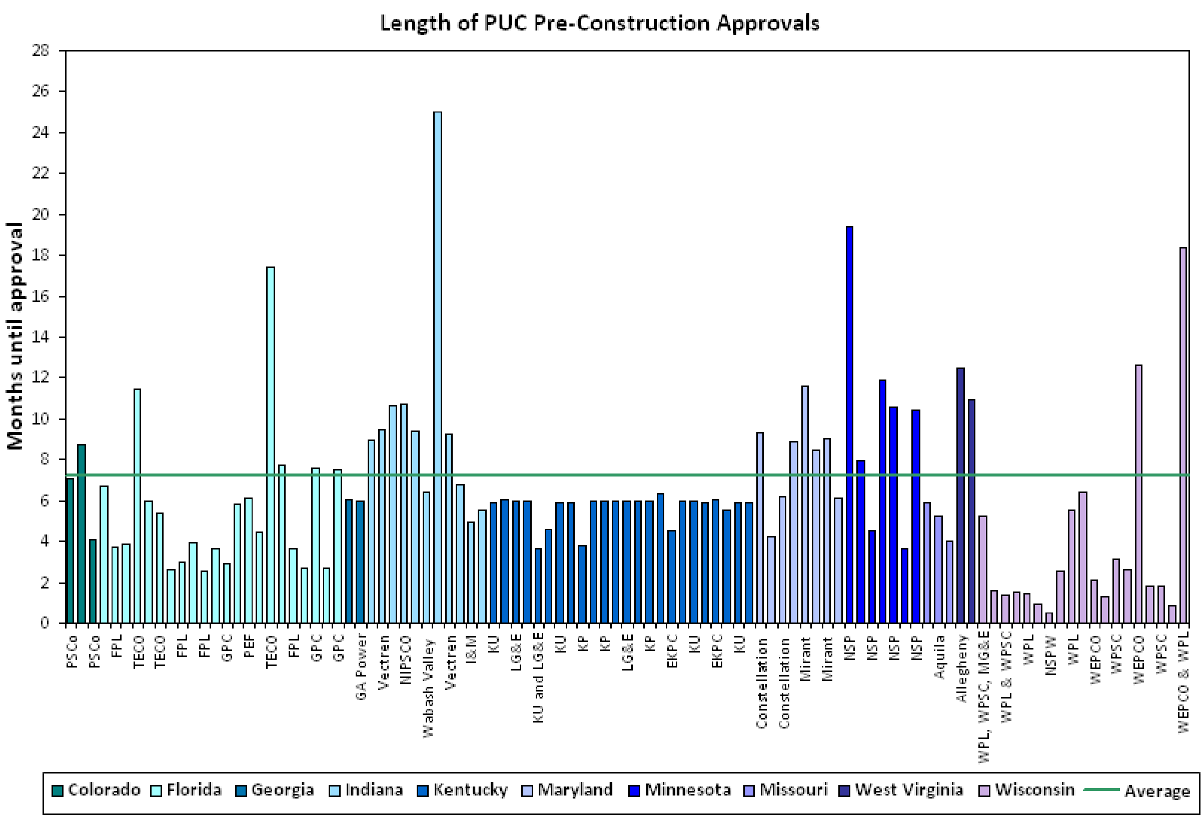

Figure 7. PUC Process Time for Approvals Prior to Construction in Ten States

The average length of approval across states[33] was approximately seven months, and only six of the 101 cases took longer than a year. Nonetheless, a great deal of variation did exist in the length of cases. Many of the longer cases had multiple intervenors or involved complex issues. Several of these approval processes are examined thoroughly in Section IV, which details specific examples as case studies.

Detailed summaries of the policies in each state are included in Appendix C, and Appendix D lists all cases used in the analysis.

[33] This is the average of each individual state's average, not the average of all cases, in order not to weight states with a large number of cases more heavily. The average of all cases was 6.33 months, and the median was 5.95 months.

SECTION IV. CASE STUDIES

In order to better explore the similarities and differences between PUC processes, this section will provide detailed analysis of six PUC cases in six different states. The case studies are centered on the PUC approval process and investigate the docket for a specific control technology upgrade or rate case. They illuminate the role of the PUC in shaping policy and defining the ultimate compliance strategy that a utility employs. With the exception of Maryland, these cases are from states that are not deregulated.

The first three cases spotlight how the PUC authorizes specific control technology choices; they include Colorado, Indiana, and Maryland. The second set of cases, including Florida, Georgia, and West Virginia, examine new and traditional financing mechanisms for compliance with air quality regulations.

A. Colorado Case Study

The Colorado case study contains a microcosm of the national debate surrounding fossil fuel choices in the U.S. This case includes vigorous stakeholder debate and involves post-combustion controls, early retirement of coal-fired generation, fuel switching, and the construction of new natural gas-fired capacity. The rate case aspect of this PUC process is also interesting, as it seems to have been modified based on concerns raised by large customer intervenors. The negotiations summarized in this case study may help EPA establish expectations for similar PUC processes as utilities and legislatures explore innovative approaches to upcoming regulations.

<u>Public Utilities Commission of Colorado</u>

The Colorado Public Utilities Commission (PUC) has full economic and regulatory authority over intrastate telecommunication services, investor-owned electric, gas and water utilities, as well as partial regulatory control over municipal utilities and electric associations. The PUC leadership is small in comparison with others; it includes three members who are appointed by the Governor and confirmed by the Senate for a term of four years. A director manages the staff and daily operations of the PUC. The agency is authorized to employ nearly 100 full time employees. The PUC is funded by fees paid by the regulated companies, not by general tax revenue. Two-thirds of the funding comes from fees paid by gas, electric, telephone, and water utilities. Within the PUC, the Energy Department is responsible for supporting the mission of the PUC to assure the availability of safe, reliable, adequate, and efficient electric, gas, and steam services to utility customers at rates that are just, reasonable, and not discriminatory.

Colorado operates under the Western Electricity Coordinating Council (WECC). For a map of the WECC operating territory, see Section I, Figure 5. The WECC is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, and is the largest and most diverse of the eight RTOs designated by NERC.

Colorado State Code

Much of the authority invested in the PUC, including utility rates, comes from Article 3.2 of the Colorado Revised Statutes (CRS). Article 3.2 includes a provision titled "Recovery of Air Quality Improvement Costs," which states that a public utility shall be entitled to fully recover from its retail customers the air quality improvement costs that it incurs. In addition, Article 3.2 includes a provision stating that for plans that include the conversion or closure of coal generation by 2015, and that will result in the utility earning less than its authorized return on equity due to a lag in the recovery of costs, the PUC will employ mechanisms to allow for cost recovery without requiring the utility to file a general rate case. These mechanisms may include a separate rate adjustment clause or other mechanisms as determined by the PUC.[34] These clauses figure prominently in the Colorado Case Study. Like most states that have retained regulation of the utility sector, the PUC requires a CPCN, as authorized under Title 40, Article 5.

Relevant Environmental Regulations

The Clean Air Clean Jobs Act

On March 15, 2010, Colorado Governor Bill Ritter introduced HB1365, the Colorado Clean Air-Clean Jobs Act (CACJ) in the House of Representatives. The House passed the bill on March 22, 2010, and the Senate passed it on March 31, 2010. Governor Bill Ritter signed the CACJ into law on April 19, 2010. The bill's lead sponsors were State Representatives Ellen Roberts (R) and Judy Solano (D) and Senators Bruce Whitehead (D) and Josh Penry (R).

The CACJ requires Colorado utilities that own or operate coal-fired generating units to develop emissions reduction plans for these facilities. These emissions reduction plans must apply to a minimum of 900 MW or 50 percent of the utility's coal-fired capacity, whichever is less, but cannot apply to any capacity that the utility is already planning to retire by January 1, 2015. The plans are required to reduce NO_X emissions at least 70 to 80 percent below 2008 levels by 2017. In addition, the Public Service Company of Colorado (PSCo) was required to examine (not necessarily implement) the impacts of repowering 900 MW of coal-fired generation. Utilities must seek approval from the Colorado PUC for these plans, and were required to submit them by August 2010. The CACJ states that the PUC will review the plans and either approve, deny, or modify them by December 15, 2010. The plans must be fully implemented by 2017.

The bill is intended to promote the use of natural gas generation as a means to meet air quality requirements. The CACJ urges utilities to give primary consideration to replacing or repowering coal generation with natural gas, as well as to consider other low-emitting resources, including energy efficiency or replacement or repowering that can be accomplished with reasonable rate impacts compared with installing emission controls on coal-fired generating units. Among other

[34] State of Colorado. House of Representatives. *House Bill 10-1365*. 67th General Assembly. 2010. http://www.leg.state.co.us/clics/clics2010a/csl.nsf/fsbillcont/0CA296732C8CEF4D872576E400641B74?Open&file=1365_ren.pdf.

considerations, when evaluating utility emissions reduction plans, the PUC will deliberate whether the proposed scenarios promote Colorado economic development.

This bill is the cornerstone for the Colorado case study. It did not pass the Colorado legislature without significant debate. Several officials opposed the bill. The Moffat County Commission sent a letter of opposition to state legislators on March 2010, and State Representative Randy Baumgardner and Senator Al White also opposed the bill. White said the bill would harm the coal industry in Northwest Colorado and could mean a loss of jobs at Twentymile Coal Company, which supplies coal to the power plants impacted by the bill.[35]

Summary

This case study explores the dynamics within the PUC process regarding early retirement for coal units and fuel switching from coal to natural gas. An added benefit of this case study is its recent completion, which makes it a timely example.

The case study features the Public Service Company of Colorado's (PSCo) plan for achieving compliance with Colorado's "Clean Air Clean Jobs Act," HB1365. The details of HB1365 are described in the previous section on Relevant Environmental Regulations, but it should be noted again that the bill requires full compliance by 2017. The timeline for the major modifications at PSCo was very compressed. The CACJ Act was signed into law in April 2010. It required an emissions reduction plan to be submitted to the PUC by August 13, 2010, and required the Commission to review the plan and enter an order by December 15, 2010. PSCo's initial emissions reduction plan included early retirement of some coal-fired units, switching from coal to natural gas in multiple units, converting some units from boilers to synchronous condensers, constructing new combined-cycle natural gas units, and placing post combustion controls on some units. PSCo also included specific financial requests for recouping costs associated with all of the modifications proposed. The financial mechanisms requested included approval of a specific rate rider and tariff sheets to allow return on construction work in progress (CWIP), and recovery of incremental 2011 plant-related costs, like accelerated depreciation and removal expenses offset by reduced rate base starting in January 2011.

Thirty-five groups were active intervenors in the consideration of this case. The major players included coal interests, natural gas interests, independent power producers, as well as large retail customers, like Wal-Mart. In addition, state and local governments entered testimony in this case, officials both from counties where coal mines are located (Mesa, Garfield, Rio Blanco, Moffat and Routt) and counties where natural gas plays are located and slated to expand (Weld). The group of intervenors held widely different views on many of the issues explored through this process since switching from coal to natural gas for nearly 1,000 MW of generation in Colorado would inevitably result in a shift of jobs from the coal industry to the gas industry.

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[35] Brian Smith. *Clean Air, Clean Jobs Act Signed into Law*. Craig Daily Press. April 20, 2010. http://www.craigdailypress.com/news/2010/apr/20/clean-air-clean-jobs-act-signed-law/.

There were many areas of disagreement over PSCo's emissions reduction plan and financial mechanisms spanning from the basic interpretation of the CACJ Act to the minutiae of modeling inputs. The procedural questions in this case were also highly contested, including the treatment and selection of confidential information, the schedule for intervenors seeking discovery, and the timeframes for submitting comments. The fate of one unit in particular, Cherokee Unit 4, generated considerable debate. Cherokee Unit 4 (350 MW) was one of the largest coal-fired units affected by the PSCo emissions reduction plan. At issue was whether to convert the unit to natural gas, retire it and build a new combined-cycle gas facility, or install emissions controls on the existing plant. Independent power producers also claimed that purchase power agreements could replace the generation at Unit 4. However, the PSCo reliability analysis demonstrated that multiple sources of power were needed at Cherokee in order to support the load demand in Denver.

In the end, the Commission-approved emissions reduction plan and approved financial instruments diverged from the initial proposals submitted by PSCo. The final PUC Order required the PSCo emissions reduction plan to be accelerated. The two units being controlled (Pawnee and Hayden 1) were ordered to have technologies installed earlier, Cherokee 3 was ordered to be retired two years earlier, and Cherokee 4 was ordered to be converted into a natural gas-fired unit by 2017. PSCo was denied the environmental cost recovery rider it sought, but was permitted to reapply through a rate case. The deferred accounting for accelerated depreciation and removal for the retired plants was approved.

Chronology

The PUC opened the docket on this case on May 7, 2010, one month after the passage of CACJ, and closed it on December 15, 2010. The entire process, which included significant energy and emissions modeling (STRATEGIST), separate approval on the emissions reduction plan by the Colorado Department of Public Health and Environment (CDPHE), several public hearings, discovery, and testimony spanned only 8 months. The case was dense with testimonies, petitions, and rebuttals.

Once the docket opened in May, stakeholders began petitioning the PUC to become official intervenors in the case. PSCo submitted a motion to limit the official intervenors to 25, encouraging some groups to merge so they would not be overwhelmed with discovery requests on such an accelerated timeframe. The PUC declined to restrict the number of intervenors and the total number included 35 official intervenors and five amicus curiae, though the PUC did encourage stakeholders to merge when possible.

On May 18, 2010, PSCo submitted a motion for reconsideration to limit data requested by the PUC to specific plants, to supply emissions data for certain units, for more time to supply all needed documents, and to postpone discovery until August. In an unusual alliance, Peabody Coal and the Gas intervenors filed separate motions for the PUC to deny the request for reconsideration, both insisting that additional data were needed and discovery should begin as soon as possible. The Commission granted the bulk of the reconsideration request.

On June 2, 2010, PSCo submitted a response to the Gas intervenors reiterating the need to limit the data to plants that will be affected and claimed insufficient time for intervenors to come up with plans that include plants not included by PSCo in their analyses. The PUC granted only part of the data requests submitted by Peabody Energy and the Gas intervenors. PSCo held a modeling workshop on June 11, 2010 to familiarize intervenors with inputs and take suggestions. The majority of intervenors submitted complaints to the docket that this process was inadequate for full participation.

On July 1, 2010, PSCo submitted its full list of modeling scenarios to the PUC. The plan was greeted with multiple petitions from intervenors expressing there were insufficient data to fully participate in the process and criticizing the narrow range of scenarios.

On August 15, 2010, PSCo submitted its draft emissions reduction plan. Testimonies were submitted throughout September 2010. In October, CDPHE found that PSCo's preferred plan did not meet the statutory requirements of the CACJ Act, as all reductions would not be implemented by December 31, 2017. PSCo modified its preferred approach by the end of October, retiring Cherokee 4 earlier. Also in October, the PUC considered a Motion for Disqualification concerning the PUC Chairman Binz and Commissioner Baker filed by the Coal Mining Association, which was denied. Testimony, rebuttal testimony and supplemental testimony regarding the new PSCo preferred approach continued through November 2010. On December 15, 2010, as mandated by the CACJ Act, the PUC approved PSCo's emissions reduction plan, a long-term natural gas contract, and certain financial instruments for recouping the costs of compliance.

Facility Description

The initial PSCo emissions reduction plan proposed modifications to five of its coal-fired plants, affecting 10 units. Two of the units in the plan are only partially owned by PSCo; they are located at the Hayden plant. The plants and units affected by the emissions reduction plan are listed in Table 4, along with their nameplate capacity, the operation date, and the expected retirement date for the unit (as listed in the PUC's Final Order). The proposed emissions reduction plan would impact approximately 1,800 MW of generation.

Table 4. Coal-Fired Public Service Plants and Units Affected by the Public Service Compliance Plan

Plant Name	Unit	Nameplate Capacity	In-Service Date	Expected life
Arapahoe	3	45 MW	1951	
	4	111 MW	1955	
Cherokee	1	107 MW	1957	2017
	2	106 MW	1959	2019
	3	152 MW	1962	2022
	4	352 MW	1968	2028
Hayden*	1	139 MW	1965	
	2	98 MW	1976	
Pawnee		505 MW	1981	2041
Valmont	5	187 MW	1964	2024

*Capacity for the Hayden units represents the amount of capacity owned by Public Service at Hayden, not total capacity.
Source: Final Order, Public Utility Commission of the State of Colorado, Docket 10M-245E.

Modification Description

The PSCo plan detailed nine possible scenarios with different replacement generation portfolios. As required by the CACJ Act, PSCo modeled a number of different scenarios capable of achieving the emissions reductions and other requirements. PSCo's preferred approach included the retirement of 903 MW of coal-fired generation. New combined-cycle natural gas-fired generation was also proposed. They considered their preferred approach to be "the least cost plan under our base case, moderate climate change assumptions and to be the lowest cost plan … assuming no carbon legislation for the first 10 years." The specific actions at each of the units in the approach are detailed in Table 5 below.

Table 5. PSCo Proposed Compliance Plan (August 15, 2010)

Plant	Proposed Modifications
Arapahoe	Accelerate retirement date for coal-fired generation at Arapahoe Units 3 and 4 to the end of 2013. For transmission voltage stability, continue to use both Arapahoe 3 and 4. Convert Arapahoe 3 to a synchronous condenser (no fuel burned). Convert Arapahoe 4 to natural-gas fired generation at the end of 2013.
Cherokee	Retire 213 MW of coal generation at Cherokee (Cherokee 1 and 2) by the end of 2011. Convert Cherokee 2 to a synchronous condenser (no fuel burned) to provide Mega Volt Ampere Reactive for voltage stability. Start construction on replacement generation at Cherokee station, which was proposed as an efficient 569 MW (summer rating) 2x1 combined-cycle generation facility fueled with natural gas. Construction of this replacement generation at Cherokee was to be completed by the end of 2015. Install in 2012 cost-effective emissions controls (selective non-catalytic reduction (SNCR) and upgraded 10 low-NO_X burners) on the 352 MW Cherokee 4. Retire the 152 MW Cherokee Unit 3 by the end of 2017, after the new 2x1 combined-cycle facility goes into operation and in order to meet the minimum emissions reductions required by the Act. Once Cherokee 3 is removed, there would be room to construct the 314 MW (summer rating) 1x1 combined-cycle natural gas facility that will ultimately be used to replace Cherokee 4. This facility would go into service by the end of 2022, and Cherokee 4 would be shut down in 2022.
Hayden	By the end of 2016, install SCR emissions controls at Hayden. (The plan stipulates that these controls would be installed only if required by the Air Quality Control Commission in conjunction with the State Implementation Plan for regional haze.)
Pawnee	By the end of 2016, install SCR emissions controls at Pawnee.
Valmont	Close Valmont 5 by the end of 2017. This will end all coal burning at Valmont Station.

According to PSCo, the combined actions in Table 5, when fully implemented, would reduce NO_X emissions from the affected generating plants by almost 90 percent, SO_2 emissions by 84 percent, CO_2 emissions by 51 percent, and mercury emissions by 85 percent. The preferred plan would require an investment of $1.3 billion in generation construction projects in Colorado.

Under the CACJ Act, the plan needed to analyze (not necessarily implement) replacing 900 MW of existing coal-fired generation. The PSCo plan met this goal. To support the new natural gas-fired capacity envisioned, PSCo worked to develop a long-term natural gas contract. PSCo had negotiated a favorable long-term natural gas agreement with Anadarko Energy Services, which they estimated would save their customers over $100 million over short-term purchases of natural gas. This contract was submitted for approval by the PUC. To enable the greater quantity of gas to reach the generation stations, PSCo sought recognition by the PUC that new gas-fired units would need adequate gas transportation infrastructure and new gas transportation infrastructure facilities would need to be constructed.

PSCo requested PUC approval of several specific financial instruments. Chief among those was a new adjustment clause, called the Emissions Reduction Adjustment (ERA), to enable CWIP to recover costs the Company will incur under the Plan. Rider costs would be rolled into base rates as new base rates were set in future rate cases. The rider would commence in January 2011. Details regarding this rider and other financial instruments and requests are listed below in Table 6.

Table 6. Financial Instruments and Approvals Requested by Public Service

Approval of a new specific investment rider, the Emissions Reduction Adjustment ("ERA") and associated tariff sheets to allow current return on capitalized construction work in progress (CWIP) at Public Service's weighted average cost of capital including our most recently authorized rate of return on equity;
Recovery of incremental depreciation expenses associated with the shortened useful lives of Cherokee Units 1, 3, 4 and Valmont Unit 5, as well as the significant portions of Cherokee Unit 2 starting January 1, 2011;
A finding that the Company's plan satisfies the requirement of "early conversion or closure of coal-based generation capacity by January 1, 2015" required by CRS §40-3.2-207 (4);
A finding that the Company has demonstrated "that a lag in recovery of the costs of the plan related to the investment required by such plan contributes to a utility earning less than its authorized return on equity" under that C.R.S. §40-3.2-207 (4), because the proposed rider does not fully compensate the Company for all costs incurred under the plan in the long-term;
A finding that actions needed to implement the approved plan are recoverable consistent with the provisions of the CACJ Act even if they occur after December 31, 2017, or in the alternative that the Commission considers it in the public interest to extend the recovery mechanisms approved by the Commission to the retirement of Cherokee Unit 4 and the construction of its replacement;

Studies, Reports, and Testimony

As required by the CACJ Act, PSCo submitted its emissions reduction plan to the PUC on August 13, 2010. It contained nine emissions reduction scenarios, nine replacement generation portfolios, and several “bolt-on” analyses. The benchmark plan retained all coal-fired capacity and applied emissions control technologies. One of the scenarios replaced nearly all coal-fired generation with gas. The PSCo preferred approach is detailed in Table 5. It included both post-combustion controls and fuel switching. Reliability issues figured prominently in PSCo’s August 13 report. Arapahoe and Cherokee stations were both seen as integral to reliably powering the Denver Metropolitan Area. The transmission system operators rely on power generation and voltage support from these sites. PSCo determined that significant generation, in the form of multiple units, needed to remain at Cherokee to ensure reliable transmission network to serve the Denver Metropolitan area load. Seventeen transmission lines run out of the Cherokee station for the greater Denver area. Thus, replacement scenarios for natural gas were focused on Cherokee. Still, retiring the largest unit at Cherokee and building a new combined-cycle generator posed some sequencing issues for PSCo due to limited physical space, so they proposed to first control NO_X at Cherokee unit 4 with SNCR, which they could do quickly and inexpensively. That approach would have enabled PSCo to stage the retirement in a less costly way, which would have a lower rate impact on consumers and allow greater flexibility for the timing and construction of the replacement generator. PSCo also asserted that this timing would have less potential impact on reliability for the Denver area.

PSCo generates a reserve capacity margin of 16.3 percent of the system's peak load obligation. All scenarios were required to keep this margin consistent. Planned outages, upgrades, retirements and replacements needed to be sequenced to maintain the capacity reserve margin. A capacity excess across PSCo generation is projected from 2011 to 2015, so many required outages were scheduled within that time period when practicable.

On September 17, 2010, the PUC submitted its independent report on the PSCo's emissions reduction plan. The review pointed out areas in which the PSCo cost estimates seemed high, such as SCR in the space-constrained Cherokee Station and at Hayden. The review also found the cost estimates for construction of new combined-cycle natural gas plants too low, given the constraints of the site.

Key Testimony

The docket for this case is by far the largest we examined; just the list of documents alone exceeds 20 pages and includes over 1,800 submissions. The plan impacts a substantial number of coal-fired plants, well over 1,000 MW, and contains plans for a significant shift from coal- to natural gas-fired generation. Given the volumes of documents in this docket it was not possible to characterize each one. Rather, we examined the docket carefully and attempted to characterize the essence of the intervenors' testimonies. A full listing of the intervenors and a summary of the rationale they supplied to the PUC to become official intervenors is available in Appendix E. A synopsis of major intervenor testimonies is offered below in Table 7. These synopses often combine several of the testimonies submitted by the intervenor.

Table 7. Synopsis of Intervenor Testimonies

Coal Interests: Peabody Energy, CMA, and ACCCE
The American Council for Clean Coal Electricity (ACCCE) testified that the loss of jobs directly and indirectly related to coal generation could cripple the Colorado economy and devastate the people that lose their jobs. ACCCE argued that PSCo's assertion that there would be a net positive effect on the Colorado economy is flawed. ACCCE supports the scenario that puts post-combustion control equipment on all facilities to meet goals set forth in CACJ. ACCCE also argued that PSCo assumed, in its sensitivities, a $20 per ton charge on carbon escalating at 7 percent per year, which exceeds the most recent PSCo IRP assumptions. ACCCE petitioned the PUCs to request that PSCo analyze replacing 900MW of coal-fired generation with new supercritical electric generation technologies – which will cost consumers less than switching to natural gas.

The Colorado Mining Association (CMA) testified that PSCo-projected differential costs among the scenarios were not credible, as follows: In November 2007, PSCo sought to reduce its natural gas burning exposure due to price volatility. In March 2010, CMA testified that PSCo raised electricity rates by 8 percent due to increases in natural gas prices. Forecasted costs of natural gas are higher than forecasts for coal. PSCo forecasts the difference between coal and gas prices increases over time. (PSCo asserted that its long-term natural gas contract with Anadarko will mute price volatility.) CMA testimony cites a NERC study stating that increased use of natural gas could result in interruptions in fuel supply and delivery which could reduce reliability of the bulk power system. CMA advocates for using the metric of the levelized cost of electricity, which uses four factors, capital charge, operation and maintenance costs, and fuel costs. CMA asserts that the metric is superior as it allocates costs of a generator across its useful life. CMA further asserts that switching to natural gas will cost Colorado ratepayers more than PSCo estimates and will dampen the CO GDP (by between \$3 and \$12 billion), by rising costs to CO's large energy-intensive economic sector. CMA estimated that the minimum number of job losses in Colorado resulting from PSCo's plan would be 30,000. The plan would adversely impact the poor, who have fewer resources for higher electricity bills and higher costs of other goods and services due to higher energy costs. CMA also commented on PSCo's modeling scenarios as inadequate, since they did not include new supercritical coal fired generation technologies. CMA believes that replacing 900MW of existing coal fired generation with supercritical new coal generation technologies falls well within the intent of the CACJ Act. In October, CMA filed a motion of disqualification claiming that PUC Commissioner Binz and others were involved in closed-door meetings to pass the CACJ Act and are not now acting impartially or in the interests of the Colorado ratepayers. This motion was denied, and the Governor's Office weighed in on this issue in support of denying the motion. Peabody Energy testified that the reliability analyses conducted do not conform with NERC and WECC requirements to examine changes in system characteristics, among other issues; that the ERA and CWIP proposals are inappropriate; and that the installation of synchronous condensers in lieu of generation is inadequate. The scenario that controls all the coal-fired generation would cost \$1 billion less than PSCo's preferred approach. Thus the rate impacts of PSCo's preferred scenario are dramatically higher. On July 6, Peabody submitted a rebuttal to PSCo modeling assumptions, claiming that natural gas fuel switching costs need to be reconsidered to include life-cycle impacts, specifically hydraulic fracturing, or "fracking." Peabody believes fracking will soon be regulated to protect drinking water, which will lead to increased costs for natural gas. The need to better assess natural gas price risks and volatility was also stressed. Peabody promoted more "green coal" options for modeling. Further, they stressed the need for reliability assurances for the plan, in particular demonstrating compliance with FERC, NERC, and WECC electric reliability standards, including assessments for transmission operation standards, transmission planning standards and voltage and reactive standards. (PSCo consistently denied the Gas intervenors' need to reproduce STRATEGIST, arguing: "The Company has always taken the position that the Strategist model data base and inputs are Highly Confidential. Under license agreements, Public Service cannot legally provide parties with the STRATEGIST model. In addition, the input files to this model contain highly sensitive commercial information, including our projected fuel costs, our incremental heat rates of units, our maintenance schedules, and many other strategic operational data.") Peabody Energy petitioned the PUC to require Anadarko and Public Service to reveal all aspects of the long-term gas contract; the petition was denied.
<u>Environmental Groups: Western Resource Advocates (WRA)</u> WRA filed an early petition for more data and earlier discovery, and supported a denial of PSCo's reconsideration request. The WRA also petitioned to see more energy efficiency options in the modeling scenarios or bolt-on analyses.
<u>Gas intervenors: Noble Energy, Chesapeake, and EnCana</u> On May 26, the Gas intervenors petitioned to deny PSCo's request for data clarification, claiming more data are required to effectively assess all new generation options, ensure that their STRATEGIST modeling has the same baseline assumptions, and that more detail on O&M and capital costs is needed. They also submitted that, "The scenarios offered by PSCo do not adequately take advantage of available generation from IPPs (540 MW in/around Denver)." They stated that PSCo's modeling approach is insufficient, as "PSCo intends the Plan it will offer to the Commission to be the only available alternative … allowing the intervening parties no reasonable opportunities to

offer alternative solutions or input, and presenting the Commission with an all or nothing approach that denies the Commission its statutory and constitutional role." The Gas intervenors entered the docket multiple times to suggest that replacing all coal-fired generation with gas-fired generation would most advantageous to Colorado. The Gas intervenors along with the coal interests sought more information regarding the details of the gas contract proposal with Anadarko.
IPPs The Colorado Independent Energy Association (CIEA) testified that the PSCo scenarios fail to adequately examine the use of existing natural gas capacity in the state. In October, CIEA petitioned the PUC that their due process was being disrupted by PSCo's refusal to run STRATEGIST scenarios utilizing more purchased power, because they were in fact running the model on additional new truncated emission reduction scenarios. Thermo UNC has existing natural gas generation, yet none of the PSCo scenarios envision new contracts with their power. CIEA argued that using existing generation would be less expensive for consumers. Southwest Generation Operating Company testified, using the STRATEGIST model, that power purchase agreements would cost ratepayers less than the PSCo self-build scenario.
Large Power Consumers Wal-Mart testified that it supports the general goals of the plan, but believes that PSCo should develop a base rate case, which allows for more systematic consideration of costs, and should not include any costs not associated with compliance with CACJ into the ERA rider. PSCo proposes to start the CWIP component as early as January 2011. Wal-Mart believes that CWIP exposes ratepayers to risk on the investment prior to any benefits received rather than having the investors shoulder the risk after modifications are complete. Climax petitioned for early discovery and for more data availability. They testified that the cost riders were not properly examined for their negative impact on the Colorado economy. Federal Executive Agencies (FEA): The FEA claims that the ERA mechanism contains two primary cost components, 1) the component for the current recovery of weighted average cost of capital associated with CWIP for projects ultimately approved for CACJ compliance and 2) the component for the current recovery of the incremental increase in depreciation expense due to the early retirement of certain coal-fired steam generation units. The Federal group claims that the methodology for the ERA proposed by PSCo is flawed, seemingly attempts to reach beyond the authority in the CACJ Act, and will lead to undue enrichment of the Company's shareholders.

Public Hearings

This case included a total of eighteen hearings from May 27, 2010 to November 20, 2010, including two pre-hearing conferences, two public comment hearings, and a status conference. The first round of hearings included ten hearings from October 21 through November 3, 2010. The PUC instructed parties that this round of hearings should focus on portions of the emissions reduction plan that were not impacted by PSCo's direct testimony. Some of the issues parties covered in these hearings included fuel costs, foreseeable emission costs, existing scenarios, the long-term gas contract, and cost recovery. The second round of hearings included three hearings, and was conducted from November 18 through November 20, 2010.

Final Determinations

The Commission examined PSCo's revised preferred plan along with the competing STRATEGIST scenarios supported by the coal, gas, and independent power producers and other testimonies it heard. The Commission evaluated fuel cost forecasts, gas price forecasts, and cost forecasts for reasonably foreseeable emission regulations (i.e., carbon controls). After much disagreement over reasonable costs per ton of CO_2, the Commission did not use a specific future cost per ton but considered each scenario's carbon emissions reductions, as well as sensitivity to carbon prices as model outputs. The final Commission-approved Plan is summarized below in Table 8.

Table 8. Approved Commission Plan (December 15, 2010)

Plant	Approved Modifications
Arapahoe	Unit 3 (45 MW) Retire and convert to synchronous condenser by 2014 and installation of 90 MVAR of new shunt capacitors Unit 4 (111 MW) Convert to from coal-fired to natural gas-fired by 2014
Cherokee	Unit 1 (107 MW) Retire by 2011 Unit 2 (106 MW) Retire by 2011 and convert to a synchronous condenser and a 90MVAR capacitor bank for system stability Unit 3(152 MW) Retire by 2015 Unit 4 (352 MW) Convert from a coal-fired generation to natural gas-fired generation by the end of 2017 Construct new 2X1 CC natural gas plant (to recover generation lost by retirement)
Hayden	Unit 1 (139 MW) Application of control technology: selective catalytic reduction by 2015 Unit 2 (98 MW) Application of control technology: selective catalytic reduction by 2016
Pawnee	Application of control technology: selective catalytic reduction, lime spray dryer, and sorbent injection controls by 2014
Valmont	Unit 5 (187 MW) Retire by 2017

The approved emissions reduction plan diverges from PSCo's initial preferred approach in the following respects:

- It requires the installment of emission control technology earlier on Pawnee and Hayden Unit 1
- It requires the retirement of Cherokee Unit 3 two years earlier (by 2015 rather than 2017)
- It requires the conversion of Cherokee Unit 4 from coal- to natural-gas fired by 2017 (rather than controlling Unit 4 with SCR and running the plant using coal through 2022).

In the final Order, the Commission recognized the need for adequate gas transportation infrastructure, including a new pipeline that will eventually be included in the gas rate base. Further, the Commission approved the long-term gas contract with Anadarko. The Commission did not approve all of the financial instruments proposed by PSCo, as outlined in Table 9.

Table 9. Financial Instrument Approvals and Denials (December 15, 2010)

Financial Instrument /Proposal	Commission Ruling
Emissions Reduction Adjustment (ERA) Rider for CWIP commencing January 2011	Rejected. Commission will allow "allowance for funds used during construction" (AFUDC), and PSCo may request actual recovery of CWIP in a general rate case.
Deferred accounting for accelerated	Approved.

Financial Instrument /Proposal	Commission Ruling
depreciation and removal (for the retired coal-fired plants)	
Jurisdictional allocator in the assignment to wholesale customers of their proportional share of costs	Approved.

The Commission committed to recommending a structure and funding source for a program to assist in retraining Colorado mining industry employees if mining jobs are lost as a result of the implementation of the emissions reduction plan.

PSCo was required to submit amended CPCNs for the coal-fired generation units slated to retire. The CPCN filing requirements were simplified to cost estimates since the deliberations were complete. PSCo was also required to submit a simplified CPCN for the new combined cycle natural gas plant planned for the Cherokee Station, for ratemaking purposes. A modified CPCN was also required for the control technology additions planned at Pawnee and Hayden.

Project Status

Within the PUC's final order approving PSCo's emissions reduction plan, a 20-day period was provided within which to file applications for rehearing, reargument, or reconsideration (RRR), beginning December 15, 2010 and ending January 4, 2011. A number of parties filed such applications.

For example, the Office of Consumer Counsel recommended reconsideration of a portion of the approval, which stated that Commission staff will determine the structure and funding of a retraining program for employees of the Colorado mining industry if jobs are lost as a result of PSCo's emissions reduction plan. OCC contended that "requiring PSCo's customers to pay for the retraining of Colorado mining industry employees who lose their jobs as a result of the Commission's Order is beyond the Commission's authority granted by the Colorado Legislature in the CACJ Act or in any other statute."

In addition, Peabody Energy Corporation submitted an RRR asserting that the hearing process for the proceeding was highly irregular, and that the time constraints imposed by the CACJ required the PUC to issue a final decision only 122 days after the date specified for filing the utility plan. Peabody further states that it is a denial of due process for the PUC to reduce the amount of time allowed for parties to present evidence.

Gas intervenors in the case, including EnCana Oil & Gas, Noble Energy, Inc., and Chesapeake Energy Corporation, also submitted an RRR regarding parts of the case referring to future long-term gas contracts, and determinations regarding the treatment of highly confidential information in the proceedings. In addition, the Colorado Independent Energy Association filed an RRR requesting the PUC clarify a number of issues relating to Arapahoe Unit 4 and Cherokee Unit 4 coal-fired electric generating units, including clarification of the ambiguity in timing for retirement and replacement of these units. On January 26, 2011, the PUC denied the motions for reconsideration of PSCo's emissions reduction plan.

Reflections

The issues raised by intervenors in this case are likely to be echoed in other PUC processes as utilities begin planning compliance strategies for the upcoming Utility MACT standards, the Transport Rule, GHG BACT, and GHG NSPS. Adding post combustion controls was a less expensive alternative than fuel-switching in nearly all the plants PSCo examined. Without explicit support from the legislature in the form of the CACJ Act, it is unclear if a PSCo plan retiring 900 MW of coal-fired generation and refueling with natural gas would be approved by the PUC or would withstand public opinion, given the impacts on the local mining community. Notwithstanding this, Colorado is in a unique position in having both coal and gas resources, which enabled them to consider job shifts within the state. Of course, construction jobs for the new gas plants and new pipelines also figured prominently into the demonstration that compliance with the CACJ Act would be beneficial to the state's economy.

The intervenors in this case were savvy and well-financed, and were able to run the same model PSCo ran to underscore their positions. Prominent lawyers and national trade groups were active in the debate. Their participation is likely in future PUC deliberations concerning coal-fired generation retirement and fuel switching.

B. Indiana Case Study

Indiana provides a useful example of a state with ample coal resources and its approach to pollution controls. This case study examines a large suite of post-combustion control technology upgrades and provides a glimpse into compliance planning through the PUC during a period of regulatory uncertainty. Some states may already have or may begin to develop laws, like Indiana's, that provide incentives to use local coal resources. The compliance paths for the Indiana case study may be imitated by other utilities in response to EPA's next generation of regulations in many states where coal mining and coal-fired generation are both located in the state.

<u>Indiana Utility Regulatory Commission</u>

The Indiana Utility Regulatory Commission (IURC) was established in the early 1900s to regulate railroad activity. In 1913, the agency was given regulatory responsibility over natural gas, water, electric, telephone, and transportation services. As an advocate of neither the public nor the utilities, the IURC is required to balance the interests of all parties to ensure the utilities provide adequate and reliable service at reasonable prices. These utilities may be investor-owned, municipal, not-for-profit, or cooperative utilities. The IURC also oversees natural gas transmission and distribution within the state. The state of Indiana has a traditional, regulated utility sector and is part of the region served by the Midwest Independent Transmission System Operator (MISO).

The IURC regulates the business of public utilities, including rates, financing, bonding, environmental compliance plans, and service territories. The IURC has regulatory authority regarding the construction of additional plants and equipment. In addition, the IURC has authority to initiate investigations of all utilities' rates and practices. The IURC promulgates rules through a process requiring notice, a public hearing, and Commission adoption, as well as approvals from the Attorney General and the Governor.

The IURC consists of four members and one chairman, all appointed by the Governor. Under state law, at least one of the members must be an attorney qualified to practice law before the Supreme Court of Indiana, and not more than three of the members can belong to the same political party. The term of the Chairman and each of the Commissioners is four years, except when a member is appointed to fill a vacancy, in which case the appointment is for the unexpired term only.

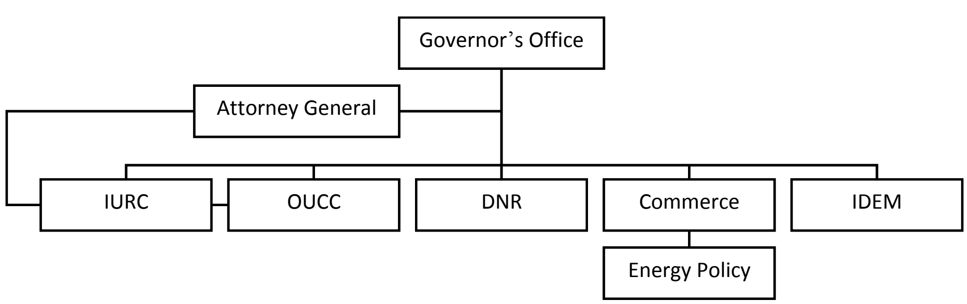

Figure 8. Executive Branch of Indiana State Government

Hearing Procedures

A formal proceeding before the IURC begins with the filing of a Petition or Complaint before the Commission, or notice of Formal Investigation from the Commission. The matter is scheduled for a Prehearing Conference to establish a procedural schedule that includes dates for the filing of testimony and the date for the Evidentiary Hearing. In some instances, a public Field Hearing may be held in the utility's largest service territory. Once the utility files its testimony, intervening parties to the proceeding and the Office of Utility Consumer Counselor (OUCC) may file their testimony, which contains evidence in support of their positions. The utility then has an opportunity to file rebuttal testimony in response to the testimony presented by intervening parties and the OUCC.

After all parties have filed their testimony, an Evidentiary Hearing is conducted by IURC on the date scheduled in the Prehearing Conference. During the Evidentiary Hearing, the parties present their direct and rebuttal testimony and witnesses are cross-examined. In every proceeding, the Commission issues its decision based on testimonies in the record. Following the close of the Evidentiary Hearing, the IURC issues an Order, or decision, on the proceeding. Determinations made by the IURC in its Orders may be appealed to the Indiana Court of Appeals.

Indiana Office of Utility Consumer Counselor (OUCC)

The Indiana Office of Utility Consumer Counselor (OUCC) is a separate state agency shown in Figure 8 that represents the interests of residential, commercial, and industrial utility customers in cases before the IURC. The IURC is designated under Indiana law to make decisions in cases involving regulated public utilities, and the OUCC serves as the consumers' legal and technical representative. The Consumer Counselor is appointed by the Governor and serves a four-year term. The OUCC was an intervenor in the Indiana case study examined below.

Indiana Code on Public Utility Commissions

There are at least six separate statutes in the Indiana code that contain unique state regulations relating to modifications at utilities and associated ratemaking instruments. This section reviews relevant statutes within Indiana state code as they pertain to how the PUC process occurs in Indiana.

1. The Environmental Compliance Plan Approval Act[36] within Indiana code allows utilities to submit a voluntary compliance plan for review and approval by the IURC. This Act also presents assurance of cost recovery, ongoing review of a utility's compliance plan, and various ratemaking provisions.

[36] Indiana State Code. Title 8. Article 1. Chapter 27. 2010. http://www.in.gov/legislative/ic/code/.

2. Indiana's Clean Coal Technology Certificate Statute[37] outlines the necessary certification for clean coal technology projects, and the associated assurance of cost recovery. This statute states that a public utility may not use clean coal technology at a new or existing electric generating facility without obtaining a Certificate of Public Convenience and Necessity (CPCN) from the IURC. The CPCN will be issued if the clean coal technology project offers significant potential to reduce sulfur or nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989. A public utility is not required to obtain a CPCN for a clean coal technology project that constitutes a research and development project.

3. The Utility Generation and Clean Coal Technology Statute[38] lays out the process for IURC approval of pollution control technology for existing coal-fired units, as well as the process for IURC authorization of financial incentives for these utilities, including the recovery of expenses.

4. The Indiana Coal and Clean Coal Technology; Research, Development, and Preconstruction Expenses Statute[39] states that the IURC shall allow a utility to recover expenses, including preconstruction costs, associated with research and development designed to increase the use of Indiana coal associated by employing clean coal technology. The commission may only allow a utility to recover preconstruction costs as operating expenses on a particular project if the commission awarded a CPCN for that project.

5. The "CWIP Statute"[40] provides for construction-work-in-progress ratemaking treatment for qualified pollution control property. This statute requires that, for ratemaking purposes, the IURC add the value of the pollution control project under construction to the value of that utility's property.

6. The Depreciation of Clean Coal Technology code[41] allows the IURC to authorize the use of accelerated depreciation (from 10 to 20 years) for clean coal technology projects, if the IURC finds that the facility where the clean coal technology is employed utilizes and will continue to utilize Indiana coal as its primary fuel source or is justified in using non-Indiana coal due to economic or governmental requirements.

Indiana's statutes for clean coal are unique to the state and are designed to provide incentives for clean coal technologies that utilize in-state coal resources from the Illinois basin.

[37] Indiana State Code. Title 8. Article 1. Chapter 8.7. 2010.
[38] Indiana State Code. Title 8. Article 1. Chapter 8.8. 2010.
[39] Indiana State Code. Title 8. Article 1. Chapter 2. Section 6.1. 2010.
[40] Indiana State Code. Title 8. Article 1. Chapter 2. Section 6.8. 2010.
[41] Indiana State Code. Title 8. Article 1. Chapter 2. Section 6.7. 2010.

Relevant Environmental Regulations

CAIR/CAMR

The Indiana case, which began in 2004, examines approvals sought to comply with EPA's Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).[42]

Summary and Chronology

In 2004, PSI Energy (PSI) initially petitioned to modify one unit, Gibson Unit 3, with flue gas desulfurization technology (scrubber). This petition was accompanied by a request that the IURC approve the CPCN as well as the use of "qualified pollution control property" in order to gain certain financial incentives, including the ability to qualify for CWIP ratemaking treatment. Five months later, on September 2, 2004, PSI submitted another petition with a two-phased plan to add and upgrade scrubbers at multiple plants to comply with EPA's upcoming CAIR and CAMR. This petition contained the following upgrade proposals and, like the earlier petition, sought to gain "qualified pollution control property" status for its upgrades for enhanced cost recovery mechanisms, like CWIP. During the years this case was under consideration, Duke Energy acquired PSI. To reduce confusion, we will refer to the applicant as PSI, which was its name when the case originated. PSI's original Compliance Plan, which was part of its CPCN application, is summarized in Table 10.

Table 10. PSI's Proposed Phase 1 Petition and Compliance Plan (Submitted September 2, 2004)

Station	Compliance Plan	Estimated In-service Date
Gibson Station	Unit 1 - wet scrubber with high-sulfur fuel Unit 2 - wet scrubber with high-sulfur fuel Unit 3 - wet scrubber with high-sulfur fuel Unit 4 - scrubber upgrade Unit 5 - scrubber upgrade	Fall 2007 Spring 2007 Fall 2006 Fall 2005 Spring 2008
Cayuga Station	Unit 1 - wet scrubber with high-sulfur fuel Unit 2 - wet scrubber & SCR with high-sulfur fuel	Fall 2008 Spring 2008
Gallagher	Units 1 & 2 – common, Activated Carbon Injection (ACI) baghouse with lower-sulfur fuel on Units 1-4 Units 3 & 4 - common ACI-baghouse	Spring 2008 Fall 2005

[42] On July 6, 2010, EPA proposed the Transport Rule, which proposes a response to the Court remand of CAIR and will replace CAIR when it is finalized. While the D.C. Circuit Court vacated CAMR, on March 16, 2011 EPA proposed Utility MACT standards for coal- and oil-fired electric generating units to regulate emissions of mercury and other hazardous air pollutants.

This plan staggers the upgrades at nine of their plants over several years. The petition requested that its earlier petition, regarding Gibson Unit 3, be consolidated for consideration. The petition specifically requested authorization in the form of a CPCN for the suite of upgrades proposed. PSI's financial requests are listed in Table 11.

Table 11. Financial Requests Specified in PSI Petition on September 2, 2004

Approving PSI's proposed Phase 1 emissions reduction equipment as qualified pollution control property and clean coal and energy projects
Providing assurance of cost recovery of capital investments made pursuant to a Commission-approved compliance plan
Providing timely recovery of financing, construction and operating costs associated with PSI's Phase 1 plan, including an initial overall rate of return of 8 percent (with periodic updates to PSI'S cost of debt), via PSI'S existing Standard Contract Riders No. 62 and 71
Providing timely recovery of emission allowance costs incurred in connection with compliance with the new SO_2, NO_X, and mercury emissions reduction requirements, via PSI's existing Standard Contract Rider No. 63
Authorizing use of accelerated (18-year) depreciation in connection with PSI's environmental compliance projects
Authorizing timely recovery of coal and equipment testing costs, and plan flexibility costs
Authorizing timely recovery of Phase I plan development and presentation costs, and Phase 2 plan development, engineering and preconstructive costs
Granting authority to defer post-in-service carrying costs, depreciation costs, and operation and maintenance costs on an interim basis, until the applicable costs are reflected in PSI's rates

Facility Description

This case study references coal-fired Gibson, Cayuga, and Gallagher power plants, originally owned by PSI and currently owned by Duke Energy. Gibson Station is the company's largest power plant, with a capacity of 3,145 megawatts. It is a five-unit facility located in Gibson County, Indiana, built between 1976 and 1982. Cayuga Station is a three-unit generating facility built between 1970 and 1993. Cayuga Station has a capacity of 1,104 megawatts and is located in Vermillion County, Indiana. Gallagher Station is a 560 megawatt, four-unit coal-fired generating facility completed in 1961. Unit 2 began operating in 1958; Unit 1 in 1959; Unit 3 in 1960; and Unit 4 in 1961. Gallagher Station is located in Floyd County, Indiana.

Modification Description and Rationale

Table 10 summarizes the available detail from the IURC documents regarding the PSI modification description. PSI proposed to modify nine of its plants, the majority of which were using high-sulfur coal. These upgrades were proposed in order to comply with EPA's CAIR and CAMR rules. Five plants were slated to be modified with wet FGD systems; these plants would then continue to burn high-sulfur coal. Three of those units were at the Gibson plant, and two were located at the two units composing the Cayuga Plant. In addition, two scrubber upgrades were proposed at Gibson. All four units at Gallagher were slated for upgrading their electrostatic precipitators with baghouses with the addition of activated carbon injection for mercury control (ACI). An SCR unit was proposed for Unit 2 at the Cayuga Plant. That modification was not pursued.

CPCN Application

The CPCN authorization request for the suite of Phase I modifications was contained in PSI's original Petition filed on September 2, 2004. PSI requested that IURC grant granting PSI a CPCN for the construction and use of clean coal technology, to the extent required by Ind. Code § 8-1-8.7-1. The CPCN was granted as part of the Settlement Agreement finalized by the IURC on May 24, 2006.

Studies, Reports, and Testimonies

There were numerous intervenors in this case whose testimony seemed to have a direct influence on the terms of the Settlement Agreement. The main intervenors included the Office of the Utility Consumer Counselor (OUCC), the PSI-Industrial Group, Nucor Steele, and the Citizens Action Coalition (CAC) of Indiana along with Hoosier Environmental Council. The PSI-Industrial Group is composed of large industrial facilities and PSI customers, including Eli Lilly, Haynes International, International Paper, and Lehigh Cement. In short, the PSI-Industrial Group, being substantial customers of PSI's electricity, commented on the specifics of the rate design, the depreciation net salvage value, and the accelerated 18-year depreciation request. There were over twenty-five hours of hearings and multiple testimony and rebuttal testimony in this case throughout 2004 and 2005.

Testimony

The issues raised within the intervenors' testimony included a discussion of PSI's exclusion of CO_2, energy efficiency, and renewable energy in its compliance analysis. In addition, CAC disagreed with PSI's generating plant retirement analysis, testifying that several of PSI's older, smaller, less efficient units are candidates for retirement, including the Edwardsport, Gallagher, and Wabash River Units. In response, PSI stated that the retirement of Edwardsport was an economic possibility, but at Gallagher and Wabash River it was more economical to continue to operate the units than retire them. In addition, CAC disagreed that PSI's proposed projects constituted clean coal and energy projects as defined in Indiana Code, and asserted that PSI's projects were not entitled to incentives; however, PSI rebutted and the IURC found that PSI's proposed equipment met the applicable definitions of clean coal technology.

In addition to discussion related to PSI's Phase I plan, PSI and intervenors discussed PSI's request for authority to recover financing, accelerated depreciation, operation and maintenance, and emission allowance costs on a timely basis via PSI's existing emission allowance cost tracking mechanisms, consistent with the Indiana CWIP statute. PSI supported its request for timely cost recovery by emphasizing that it continued to face significant environmental compliance costs, and timely recovery of costs is important from a credit quality perspective.

In response to testimony from CAC's witness and the PSI Industrial group, modifications were made to the initial proposal. Some of the major changes included:

- The ACI component of the four baghouses at Gallagher was dropped – OUCC stated that the technology was new and would likely be more cost effective in the future, so PSI should postpone adoption of the ACI component. Further, since EPA was proceeding at the time with a cap-and-trade approach to mercury control, PSI could forego the ACI construction and purchase emission allowances to comply with the mercury rule.
- PSI agreed to use a 20-year depreciation rate as opposed to its originally requested 18-year depreciation rate.
- PSI agreed to use a 10 percent net negative salvage value as opposed to the originally requested 20 percent.
- The allocation of rates in Rider 62 and 71 would be based on demand (kW-hours, rather than kW).
- PSI agreed to credit customers through Rider 71 with $120,000 annually to reflect the anticipated reduction in operation and maintenance costs associated with removing the ESP at Gallagher.

These changes were reflected in a Settlement Agreement, which was eventually reached. However, the CAC filed testimony in opposition to the Settlement Agreement citing the lack of aggressive renewable energy options, energy efficiency options, shutdown considerations, and insufficient attention to carbon emissions. PSI filed a rebuttal based on cost analysis of all options. On May 24, 2006, the IURC found the Settlement Agreement well supported by the evidence in testimony and believed the Phase I plan to be the most cost effective way to comply with EPA's upcoming regulations. Further, the project was approved for various clean coal financial incentives and CWIP.

<u>Studies</u>

In preparation for anticipated Federal CAIR and CAMR compliance deadlines, PSI engaged in a compliance planning process to comply with the SO_2, NO_X, and mercury emissions reduction requirements long before these rules were finalized in 2005. PSI was required to develop a Compliance Plan. To do so, PSI engaged in a multiple-stage process, including: developing key price forecasts, using an Integrated Planning Model created by ICF Consulting, ranking various compliance alternatives by asset value, using Cinergy Corporation's Engineering Screening Model, using the STRATEGIST Model to rank integrated resource and environmental compliance plans, and analyzing the results based on overall economics, consideration of various levels of risk and uncertainties, financing implications, and rate impacts.

<u>Public Hearings</u>

This case consisted of nine total hearings over the course of two years, the first occurring on June 7, 2004, and the last on March 29, 2006. There were four preliminary hearings consisting of five hours total, and five evidentiary hearings consisting of 29 hours total.

Final Determinations

The IURC made a determination on the full PSI request on May 24, 2006. In response to testimony from the intervenors, there were several issues that required further study, negotiations, and compromise. The key points of contention were highlighted previously within the Testimonies section. A Settlement Agreement was originally proposed on December 9, 2005. Further testimony and rebuttal were entered into the docket and a Settlement Agreement was finally reached, without the consent of the CAC. A summary of the compromises contained in the Settlement Agreement regarding the Rate Design is provided in Table 12.

Table 12. Areas of Compromise in the Financing and Rate Design for the Settlement Agreement

Area of Compromise	Final Determination in the Settlement Agreement
Incremental Incentive Return on Equity	OUCC opposed PSI's requested return on equity; however, this request was withdrawn in the Settlement Agreement.
Accelerated Depreciation	The PSI Industrial Group testified that the accelerated depreciation should be 20 years, rather than 18 years (Code allows for anywhere between 10 and 20 years). The Settlement Agreement states 20 years.
Depreciation of Net Salvage Value	PSI-Industrial Group testified that PSI should use a net negative salvage factor of 5 percent as opposed to 20 percent. The Settlement Agreement provides a compromise at a 10 percent net negative salvage factor for environmental compliance plan equipment.
Rate Design	PSI Industrial Group testified that the Riders 62 and 71 should be more precise since they are of such a high magnitude, and therefore the revenue adjustment factor should be calculated using kilowatts instead of kilowatt-hours (shifting from energy-based to demand-based). PSI did not think the suggested new calculation would be a benefit to Industrial customers (since they have lower load factors), and is a departure from normal billing procedures. However, PSI agreed to these changes in the Settlement Agreement.
Off-System Sales and Allocation of Compliance Plan Fixed Costs:	PSI Industrial Group testified that off-system sales should contribute a proportionate share of cost recovery for the compliance plan. PSI testified that these suggestions lacked specificity and that the compliance plan is based on generating sufficient capacity for the native load customer needs. Further off-system sales are not firm in nature and are already credited to ratepayers in a 50/50 sharing sales profit contract (Rider 70). In the Settlement Agreement, there was no allocation of fixed costs to off-system sales, nor will any modifications be made to PSI's Standard Contract Rider No. 70 in this Cause. Variable costs, including emission allowance costs, associated with off-system sales, should be allocated appropriately to off-system sales.
Updating Jurisdictional Percentages:	PSI Industrial Group opposed PSI's proposal to change Riders 62 and 71 retail electric jurisdictional allocation percentages to reflect the

Area of Compromise	Final Determination in the Settlement Agreement
	termination of service. The Settlement Agreement allows those allocations to remain intact.
Operation and Maintenance	PSI Industrial Group testified that the pollution control costs should not be recovered on a forecasted basis, but after-the-fact. PSI testified that the current Rider 71 already results in some regulatory lag and Rider 62, the CWIP Rider are filed together semi-annually. To recover costs after-the-fact would increase regulated utilities' financing costs and result in higher costs to serve customers.
AFUDC	Authority to defer post-in-service allowance for funds used during construction (AFUDC), depreciation costs, and operation and maintenance costs on an interim basis, until the applicable costs are reflected in PSI's retail electric rates. For future CWIP and general ratemaking purposes, post-in-service AFUDC shall be added to the cost of the plant and recovered over a 20-year period.

Table 12 provides additional insights into how utilities use existing riders for rate recovery, as discussed in Section II. In addition to the changes outlined in Table 12, PSI also withdrew the proposed ACI components at all four units at the Gallagher plant in response to the consumer group's testimony. The proposed SCR at Cayuga Unit 2 was also removed from the final Phase I Compliance plan, though we did not see any direct testimony requesting thjs. To date, Cayuga Unit 2 does not have an SCR system. The final Phase I Compliance Plan that is contained in the Settlement Agreement is reproduced below as Table 13.

Table 13. PSI's Final Phase 1 Compliance Plan in Settlement Agreement (Exhibit G1)

Station	Compliance Plan	Construction Date	Estimated In-service Date
Gibson Station	Unit 1 - wet scrubber with high-sulfur fuel	11/2004	12/2007
	Unit 2 - wet scrubber with high-sulfur fuel	11/2004	6/2007
	Unit 3 - wet scrubber with high-sulfur fuel	5/2004	12/2006
	Unit 4 - scrubber upgrade	9/2005	12/2005
	Unit 5 - scrubber upgrade	10/2006	6/2008
Cayuga Station	Unit 1 - wet scrubber with high-sulfur fuel	3/2005	12/2008
	Unit 2 - wet scrubber & SCR with high-sulfur fuel	3/2005	6/2008
Gallagher	Unit 1 - baghouse	4/2006	11/2007
	Unit 2 - baghouse	4/2006	11/2007
	Unit 3 - baghouse	5/2006	5/2008
	Unit 4 - baghouse	5/2006	12/2008

Project Status

All of the upgrades listed in the Settlement Agreement and shown in Table 13 have been put in place. At the Cayuga Plant, a wet FGD system came online on Unit 1 in 2006, and for Unit 2, a wet FGD system came online on Unit 2 in 2008. We confirmed the presence of scrubbers in EPA databases as well as on the Duke Energy website. At Gibson Station, wet FGDs with ESP have been put on Units 1, 2, and 3. We cannot confirm the scrubber upgrade on Unit 4, but the original scrubber came online in 1994. Gibson Unit 5 is co-owned by Wabash Valley Power Association and Indiana Municipal Power Agency, and according to the Duke Energy website, all five units have sulfur dioxide scrubbers. Also, based on the Duke Energy website, baghouses were installed at four units at the Gallagher plant in 2008.

Reflections

This case study provided a good example of a PUC process where the final result is impacted by the process based on the testimony of the intervenors. The PSI-Industrial Group was successful in achieving many of its recommendations relating to the financing and rate design features PSI proposed. The CAC was less successful, perhaps in part because renewables are rarely cost effective in the absence of a state RPS, which Indiana has not yet adopted. The CAC also pushed for more consideration of carbon, which was factored into the analysis, but the post-combustion controls proposed were still cost effective even in the carbon price scenarios modeled. The OUCC succeeded in removing the proposed ACI from each of the four units at the Gallagher Station where the ESP systems were proposed to be updated using baghouses. While some stakeholders may raise concerns that the ESP systems may not achieve the same reductions as ACI, the role of these procedures is primarily economic in the regulated environment. The OUCC was advocating on behalf of customers' rates, betting that ACI costs in the future would be lower, or that PSI/Duke could meet compliance needs using mercury allowances. Given that the D.C. Circuit vacated CAMR, no allowances will be available for compliance with the upcoming Utility MACT rule. However, the initial plan stated that the baghouses would be constructed with the ability to retrofit with ACI, or another mercury control such as powder activated carbon (PAC), as needed.

While reliability is well within the purview of the IURC, and PSI was supplying electric utility service to over 700,000 customers, few details were found in the docket regarding the shutdown schedule for the nine PSI plants. While PSI did indicate that staggering the shutdowns was critical for reliability, there appeared to be little scrutiny regarding reliability.

It is worth noting that PSI did seek to initiate the PUC process and begin its compliance planning in mid-2004, prior to final EPA rules limiting emissions (CAIR and CAMR). PSI, the intervenors, and the IURC seemed to be able to proceed with deliberations for the PSI Compliance Plan even under some regulatory uncertainty. However, the entire process took the better part of two years. Construction of the scrubbers each took about two to three years. No information was available regarding how much time PSI invested in the application process prior to submitting its initial petition. For example, it is unknown how much time was required to work on the IPM modeling that was contained in the Compliance Plan.

Lastly, it should be noted that the IURC was recently in the press regarding the appearance of a "revolving door" between Duke and the IURC. That issue led the Governor to terminate the former IURC Chairman. Further fallout regarding the close relationship between Duke and the IURC has recently resulted in the resignation of a top official at Duke. For more details on these issues, see the articles reproduced in Appendix F.

C. Maryland Case Study

The Maryland case was chosen as an example of the CPCN process for post-combustion controls. The case features a wet scrubber, pulverized activated carbon injection, needed ductwork, and a baghouse installation. The application of these technologies is particularly relevant because they are possible compliance strategies for EPA's upcoming Utility MACT and Transport Rule. Lastly, this case study is a good process contrast between a deregulated state and the other five regulated states.

Maryland Public Service Commission

The Maryland General Assembly established the Public Service Commission (PSC) in 1910 as an authority to regulate public utilities and certain passenger transportation companies within the state. Currently, the PSC regulates gas, electric, telephone communications, water, and sewage disposal companies. The PSC has authority on affairs relating to rate adjustments, modifications to the type or scope of service, promulgation of new rules and regulations, and the quality of utility service.

Maryland, having a deregulated power sector, is part of the region served by PJM Interconnection, LLC (PJM). PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in 13 states (including Maryland) and the District of Columbia.

The Maryland Governor, with the advice and consent of the Senate, appoints the PSC's Chairman and four Commissioners. The terms of the Chairman and each of the Commissioners are staggered and five years in length. All terms begin on July 1.

The PSC sets utility rates for distribution, and supervises and regulates the activities of public service companies. In addition, the PSC gathers and maintains records of public service companies, reviews plans for service, inspects equipment, audits financial records, promulgates and enforces rules and regulations, defends its decisions on appeal to state courts, and participates in relevant cases before federal regulatory commissions and federal courts. Pursuant to Maryland state law, the PSC releases an annual report highlighting key issues and achievements within the state.

Maryland Code on Public Utility Commissions

As we mention throughout this report, every PUC is unique. Part of what makes each PUC unique is the underlying laws that govern the PUC operating procedures. Toward that end, we thought it would be helpful to include summaries of some relevant portions of Maryland's code as it relates to PUC approvals in this Section. Under the Annotated Code of Maryland (the MD Code), the PSC has the authority to issue a Certificate of Public Convenience and Necessity (CPCN) in connection with a company's application to construct or modify a generating plant or to construct or modify transmission lines designed to carry a voltage in excess of 69,000 volts.

Section 7-207 of the Maryland Code lays out the state requirements for obtaining a CPCN when beginning construction of a generating station or modification. This section defines "construction" under Maryland law, and includes details regarding the application process for obtaining approval to construct, the public hearing process for applications, and the final action of the PSC in granting the Certificate. Specifically, an application must address the effect of the generating station, modification, or overhead transmission line on:

- (i) the stability and reliability of the electric system;
- (ii) economics;
- (iii) aesthetics;
- (iv) historic sites;
- (v) aviation safety as determined by the Maryland Aviation Administration and the administrator of the Federal Aviation Administration;
- (vi) when applicable, air and water pollution; and
- (vii) the availability of means for the required timely disposal of wastes produced by any generating station.

A CPCN is not required for a company to construct a generating station below 70 MW, although a written application for approval is required.

Section 7-207 of the Code specifies that installation of pollution control equipment, or a change in operating method, in order to comply with the Clean Air Act is considered a modification requiring a CPCN. It also requires expedited consideration of CPCN applications for modifications required to comply with the federal Clean Air Act or Maryland's Healthy Air Act (discussed below).

Under Section 7-208 of the MD Code, to obtain a CPCN (required under Section 7-207), a person must file an application with the PSC at least two years before construction of the facility will commence. The PSC may waive the two-year requirement on a showing of good cause. Upon receipt of the application, the PSC provides notice to all interested persons, and holds a public hearing. Within 90 days of the hearing, the PSC must either deny or grant the Certificate subject to conditions the PSC determines to be appropriate. In each Certificate issued, the PSC includes the requirements of all applicable federal and state environmental laws and standards.

<u>Relevant Environmental Regulations</u>

Maryland Healthy Air Act

A brief summary of the Maryland Healthy Air Act (HAA) is provided here because it is the main regulatory driver for the case study. The HAA is a four-pollutant law that requires the reduction of both ozone and fine particulate-related emissions from Maryland's seven largest coal-fired power plants, owned by Allegheny Energy Group, Constellation Energy Group, and Mirant Corporation. The HAA was developed for the purpose of bringing Maryland into attainment with the National Ambient Air Quality Standards (NAAQS) for ozone and fine particulate matter by the federal deadline of 2010.

The HAA and subsequent regulations will reduce NO_X by 70 percent in 2009 and 75 percent in 2012, SO_X by 80 percent in 2010 and 85 percent in 2013, and mercury emissions by 80 percent in 2010 and 90 percent in 2013. The HAA also requires Maryland to become a member of the Regional Greenhouse Gas Initiative (RGGI), which was established to reduce carbon dioxide emissions. The Maryland Department of the Environment (MDE) has implemented the HAA through state regulations.

Summary and Chronology

On August 23, 2006, Constellation Power Source Generation, Inc. (CPSG) submitted an application for a Certificate of Public Convenience and Necessity (CPCN) from the Maryland Public Service Commission (MDPSC). The modification request included the installation of air pollution control equipment including a wet flue gas desulfurization (FGD) system, a pulverized activated carbon injection duct, and a baghouse. In addition, upgrades were proposed on the boilers in units 1 and 2 to achieve a higher generating output to compensate for the parasitic load to run the air pollution control equipment. CPSG's application was designed to satisfy the requirements of Maryland Healthy Air Act. CPSG requested an expedited CPCN review process. Throughout the remainder of 2006 and the first half of 2007, CPSG submitted several technical amendments describing revisions to the proposed modifications. Three public hearings were held in addition to one pre-hearing. The final CPCN was granted on June 4, 2007, 10 months after the formal process began.

This case study will review the MDPSC procedure for granting the CPCN for CPSG. The bulk of the documents associated with this case were found on the MDPSC website in its specified case jacket.

Facility Description

Brandon Shores, the largest coal-fired electric generating plant in Maryland, consists of two pulverized coal units, with a combined nominal generating capacity of 1,370 MW. Units 1 and 2 were constructed in 1984 and 1991, respectively. Brandon Shores is located in Anne Arundel Country, Maryland.

Modification Description and Rationale

The modifications CPSG requested included the construction of wet FGD technology and a mercury control duct with a baghouse. The components originally requested in the CPCN are listed in Table 14.

Table 14. Constellation Modification Components

Initially Proposed Project Components
Installation of a wet FGD system and associated facilities ("FGD system") for each unit.
Installation of a fabric filter baghouse on each unit.
Installation of sorbent injection equipment for removal of mercury and sulfuric acid mist.
Installation of a single dual-flue 400-foot stack that will serve the FGD systems for both units.
Installation of enhancements on the steam turbine to improve efficiency of the steam cycle and any necessary enhancements to the transmission interconnection facilities at Brandon Shores.
Upgrades to the existing steam boilers to enhance performance. The upgrades may increase the maximum heat input of the units.
Installation of material handling equipment for limestone, other AQCS reagents and gypsum.
Reconfiguration of the coal yard to accommodate coal alternatives created by the installation of the FGD systems.
Installation of water and wastewater treatment facilities.
Installation of handling and storage systems for water and wastewater treatment solids and fabric filter waste.

The parasitic power demand to operate the control technologies was estimated at 35 MW (total both units). To compensate for the lost output, power block enhancements were also proposed including an upgrade of the high-pressure turbine steam path components. The results of the upgrade would improve heat rate and increase generator output. The proposed power block enhancements were estimated to generate an additional 60 MW, which would recover about 35 MW of parasitic load and provide a potential net gain of about 25 MW of additional power (total of both boilers) for the grid.

CPCN Application

CPSG submitted its CPCN application on August 23, 2006. The application consisted of an official application document containing all the application filing requirements needed to request that the MDPSC grant a CPCN for their proposed modification. It also contained a specific request that the review process for the CPCN be expedited to enable compliance with Maryland's Healthy Air Act and have authority by May 1, 2007. The application also contained the requisite Environmental Analysis, which reviews and analyses the potential impacts of the project on numerous environmental issues, including noise, air quality, archeological and historic sites, construction issues, land impacts, waste stream, and leaching issues.

Two amendments were filed to the Application, one on November 28, 2006, and one on March 7, 2007. The first amendment included refinements to the design and updated impact assessments. The second amendment, filed after the conclusion of the public hearings, contained design revisions and supplemental information regarding the stack flue parameters, the raw water treatment system, the gypsum and limestone materials handling systems, and fugitive gas emissions estimates.

Studies, Reports, and Testimonies

The Maryland Department of Natural Resources Power Plant Research Program (PPRP) submitted testimony that discussed their findings on the environmental and socioeconomic impacts of the proposed modifications. PPRP is the branch of state government responsible for coordinating the interagency review of projects requiring a CPCN across the other relevant state agencies, which in Maryland include the Department of the Environment (MDE), the Department of Agriculture, the Department of Business and Economic Development, the Maryland Energy Administration, the Department of Planning, and the Department of Transportation. The PPRP then submits a coordinated environmental and economic review to the PSC. The involvement of so many different agencies appears to be fairly unique. It is likely that such a degree of coordination adds to the PUC process time.

PPRP staff is in contact with the applicant prior to the official application submission to ensure an efficient process. According to PPRP testimony, "The PPRP review process usually begins well before an application is submitted to the PSC. Once the determination has been made that the project will require a CPCN, PPRP meets with the Applicant to identify any major issues and generally outline what analysis or fieldwork will need to be accomplished as part of the formal application. It is to the benefit of all parties to come to an early agreement regarding various studies that need to be performed. The goal is to ensure that any and all concerns are identified early in the process so that they can be addressed, either through studies performed by the Applicant or by PPRP. This safeguards both the state and the Applicant against serious issues coming to light at the last moment, potentially delaying a needed project." This note suggests that there is a pre-application process, which would add time to the front end of the PUC process that is not captured in this discussion.

The PPRP's synthesized report, entitled Environmental Review of Proposed Air Pollution Control Project at Brandon Shores, was submitted as direct testimony to the PSC. The review includes an assessment of potential impacts to air quality, noise, terrestrial, ecological, ground water, surface water, socioeconomic, aesthetic, and cultural resources. The PPRP-coordinated report found that the project would comply with all applicable regulatory standards and would not result in adverse environmental or socioeconomic conditions. The results of the Environmental Review Document were in favor of granting the CPCN, subject to several conditions.

Conditions for CPCN approval by the interagency process were transmitted to the PSC in a letter accompanying the Environmental Review on February 5, 2007. The conditions included 16 pages of technical specifications, including: general provisions, such as access to the facility during construction; applicable air quality regulations (PSD, NSR, monitoring, discharge limits, New Source Performance Standards [NSPS], National Emission Standards for Hazardous Air Pollutants [NESHAP], Best Available Control Technology for carbon monoxide and acid mist, and Lowest Achievable Emission Rate for VOCs); other emission limitations and operating restrictions; testing, recordkeeping and reporting; by-products and waste; water supply and water discharge; noise impacts; ecology; and traffic.

For the Brandon Shores Project, the CPCN also served as the Prevention of Significant Deterioration approval, Nonattainment Air New Source Review approval, and air quality construction permit.

The Office of Staff Council at the Public Service Commission submitted direct testimony regarding the effect that the proposed project would have on the reliability and stability of the electric system in Maryland. These are two of the factors required to be considered under Sections 7-207 and 7-208 of Maryland Code Law, as described previously. The PUC Reliability analysis recommended that the CPCN be granted as it would result in significant environmental benefits and it would also be beneficial for the grid.

With respect to reliability, the PUC noted in its analysis that it was imperative that the plant remain online during summer months. As mentioned earlier, Maryland is part of PJM, which has experienced spikes in Locational Marginal Prices due to grid congestion during peak summer load. The report states that the loss of generation from Brandon Shores during construction could be compensated by supplies from other electrical facilities in Maryland and out-of-state depending on demand and prevailing grid conditions. The outage would have minimal impacts for the grid during the non-summer months.

The report further noted that the forced outage rate of the plant could increase as a result of failures in the scrubber systems, though this possibility would be minimized by the dual redundant system being capable of operating units 1 and 2 independently. The most likely failure modes could include baghouse filter bag failures, fan motor or pump failures, or equipment blockage. Installation of separate air quality control systems also supports this redundancy and makes the plant more reliable. The outages for construction were planned for the last quarter of 2009 (Unit 1), and the first quarter of 2010 (Unit 2).

In addition to the PUC process outlined in this section, CPSG was required to notify PJM of the planned construction time, during which the units would be offline.[43]

<u>Public Hearings</u>

Three public hearings and one pre-hearing were held to review this application. On February 22, 2006, the Maryland PSC held a hearing in the evening to increase public participation. The questions discussed at the hearing included the projected length and estimated completion date of the project, the plan for the effluent water used in the project, the details of the construction and control technology of the stacks, the environmental regulations in place to protect Stoney

[43] PJM is responsible for coordinating and approving requests for outages of generation and transmission facilities, as necessary, for the reliable operation of the PJM RTO. PJM maintains records of outages and outage requests for these facilities. In order to be classified as a Planned Outage, the PJM Member submits the initial outage request to PJM through eDART no later than 30 days prior to the Operating Day in which the Planned Outage is to begin. (Source: PJM.)

Creek from runoff, and questions regarding traffic and noise related to the project. In addition, the public discussed air pollution control technology regulated under Maryland's HAA, signed in 2006. The hearings for this case did not produce any issues that delayed the approval process.

Final Determinations

The parties engaged in negotiations to reach agreement on the final recommended licensing conditions. These discussions resulted in an Agreement of Stipulation and Settlement, which included a list of final recommended conditions for the CPCN on May 14, 2007. The list of final recommended conditions was nearly identical to the list of conditions set forth by the PPRP-led interagency letter, described above. There was an additional condition that if CPSG was unable to secure agreements for the use of all of the synthetic gypsum, it would be properly disposed of in accordance with existing rules. Perhaps because the environmental permitting process was part and parcel of the PUC process, many detailed environmental issues were explored. That inclusion is fairly unique among PUC processes; more often there is a separate environmental review and permitting process through the environmental agency. The period of appeal for the agreement was shortened to seven days in order to expedite the procedure and begin construction. CPSG was also required to certify that it was in compliance with all applicable emissions limitations and standards. Additional discussions with MDE were necessary to submit the certification. It was granted by MDE on May 23, 2007.

On May 25, 2007, the MDPSC submitted a proposed hearing order to grant the CPCN for CPSG's modifications to the Brandon Shores Plant. This approval took effect on June 4, 2007.

Project Status

The upgrades to the Brandon Shores power plant were completed, and the plants were back online, in March 2010. Together, the FGD and baghouse at Brandon Shores are achieving a 95 percent reduction in SO_2 and a 90 percent reduction in mercury emissions. Construction for these upgrades began in 2007, and took three years to complete.

Reflections

The application and award of the CPCN appeared fairly straightforward for a project intended solely to comply with Maryland's Healthy Air Act; however, the number of conditions placed on the approval extended the process. While CPSG requested that the CPCN application be expedited, the application was granted on June 4, 2007, 10 months after the formal application was submitted on August 23, 2006. Again, it is significant that the environmental permitting process was included within the PUC process, as that can also be time consuming. This 10-month timeframe does not include the time CPSG spent developing their legal application with its 158-page Environmental Analysis. According to Constellation, the company worked on the documents for roughly nine months prior to commencing with the official CPCN application. Factoring in the front-end work, the total time required for Constellation to receive approval to make modifications for meeting the requirements of the Healthy Air Act was 19 months, over a year and a half.

D. Florida Case Study

The following case study involving Florida Power & Light was chosen as an example of a process whereby the PUC denied a utility's request for accelerated recovery for new, clean power plants. In this case study, we examine the nature of the request and its denial. While the original financing piece was rejected, the projects are in fact moving forward, having gone through a more traditional rate case PUC approach.

Florida Public Service Commission

The Florida Public Service Commission (PSC) was created by the Florida Legislature in 1887 to provide regulatory oversight to the state's railroad operations. In 1974, the Legislature gave the PSC rate structure jurisdiction over municipal and rural cooperative electric utilities.

The PSC currently oversees electric, natural gas, telephone, water, and wastewater services within the state. The PSC exercises regulatory authority over utilities in terms of rate base and economic regulation, competitive market oversight and monitoring of safety, reliability, and service issues. During 2009, the PSC regulated five investor-owned electric companies and seven investor-owned natural gas utilities. While the PSC does not fully regulate publicly owned municipal or cooperative electric utilities, it does have jurisdiction, with regard to rate structure, territorial boundaries, bulk power supply operations and planning, over 35 municipally owned electric systems and 18 rural electric cooperatives. The PSC has jurisdiction, with regard to territorial boundaries and safety, over 27 municipally owned natural gas utilities and also exercises safety authority over all electric and natural gas systems operating in the state.

The PSC consists of five members appointed by the Governor and confirmed by the Senate. Commissioners serve four-year terms. The Chairman is elected by a majority vote of the Commissioners to serve as chair for two years.

Florida operates under the Florida Reliability Coordinating Council (FRCC), an Independent System Operator with delegated authority from the North American Electric Reliability Corporation (NERC). The purpose of the FRCC is to ensure and enhance the reliability and adequacy of bulk electricity supply in Florida. The FRCC region is within the Eastern Connection and includes almost all of Florida, except for areas west of the Apalachicola River, which are within the SERC Region.

Florida State Code

Before addressing the 2010/2011 rate case, it should be noted that in Florida the costs associated with pollution control projects on existing power plants are recovered through the Environmental Cost Recovery Clause (ECRC). The ECRC has been in place since 1993, when the Florida Legislature passed a law allowing utilities to recover the costs "of the utility's prudently incurred environmental compliance costs, including the costs incurred in compliance with the Clean Air Act, and any amendments thereto or any change in the application or enforcement thereof, through an environmental compliance cost-recovery factor that is separate and apart from the utility's base rates."[44]

The ECRC is set on an annual basis, based on a projection of the utility's environmental compliance costs and adjusting for any variation between projected and actual costs in the previous year. In FP&L's most recent ECRC filing, the Florida Public Service Commission (PSC) approved environmental recovery costs of over $172 million for calendar year 2011. This includes over $43 million for a new project to install electrostatic precipitators on four oil-fired units. FP&L is undertaking the project to comply with expected new requirements for the Utility MACT standards.

Summary

This case study focuses on a rate case filed by Florida Power & Light (FP&L) in 2009 to adjust rates for 2010 and 2011. Unlike the other case studies in this report, which largely focus on approvals for and cost recovery of investment in pollution controls on existing power plants, this case provides an example of a utility developing a long-range plan for a progressively cleaner generation fleet and seeking recovery for those investments through increased base rates and an automatic adjustment mechanism. The case study shows that PUCs may be reluctant to provide accelerated cost recovery for new power plant projects, preferring to review such projects in the context of a general rate case. However, to the extent that such projects deliver tangible economic benefits to ratepayers – through reducing fuel costs, for example – the case study indicates that interested parties and the PUC were willing to provide accelerated recovery up to the level of the cost savings.

Background: 2005 Rate Case and the Generation Base Rate Adjustment

After nearly 25 years of keeping customer rates flat or in decline, FP&L filed a request in March 2009 to increase base rates in Florida for the years 2010 and 2011. The request came on the heels of FP&L's 2005 rate case, in which FP&L agreed to hold base rates flat. In return, the PSC allowed recovery of expenses for large capital projects that were planned as part of FP&L's efforts to meet demand projections with a newer, cleaner fleet of power plants through a mechanism called the Generation Base Rate Adjustment (GBRA).

The GBRA allows FP&L to increase base rates to recover capital costs associated with new generation facilities as those facilities enter into commercial service. In other words, it allows FP&L to add completed generation projects to the rate base without filing a new rate case. In order to qualify for the GBRA, the project must go through the siting certification process, the "Need Determination," under the Florida Power Plant Siting Act. Once the project receives the Need Determination and is then constructed and placed in service, it qualifies for the GBRA. The GBRA adjusts the revenue requirement to accommodate the capital costs that were projected in the Need Determination.[45] In addition to rolling capital costs into the rate base, a separate

[44] The Florida Statutes. Title XXVII. Chapter 366. 8255 Environmental Cost Recovery. 2010.

[45] Any difference between projected and actual costs would be credited as part of a separate charge.

mechanism, the fuel cost recovery clause, also adjusts costs downward for the fuel savings expected from the new facilities. In this way, ratepayers receive the financial benefits of the new facilities contemporaneously with paying for the costs.

Facility Description and Modification

From 2006 through 2009, FP&L utilized the GBRA to flow through $387 million to the rate base for three projects: Turkey Point Unit 5 (1100 MW combined-cycle natural gas) and West County Energy Center Units 1 and 2 (2500 MW combined-cycle natural gas). FP&L projected that its power plant upgrades between 2003 and 2009 resulted in over $3 billion in fuel savings.

FP&L's 2009 Rate Case Requests marked a departure in holding rates constant. In its 2009 filing, FP&L asked for an increase in base rates of $1.04 billion in 2010 and $247 million in 2011. FP&L explained that the impetus for the increase was largely attributable to two factors: (1) $5.6 billion in capital expenditures between 2006 and 2010; and (2) a dramatic decline in sales growth. Due to a decrease in fuel costs, FP&L projected that customer bills in 2010 would actually decrease 4.5 percent from 2009 levels. However, in 2011, FP&L projected that customer bills would increase 7 percent from 2009 levels.

In addition to the rate increase, FP&L also proposed indefinitely extending the GBRA, which was set to expire at the end of 2009. Extending the GBRA could have potentially allowed FP&L to recover $3.2 billion from 2010-2015 for three planned projects: West County Unit 3 (1250 MW combined-cycle natural gas), Cape Canaveral Energy Center (1250 MW combined-cycle natural gas), and Riviera Beach Energy Center (1250 MW combined-cycle natural gas). FP&L expected that the fuel savings gained from utilizing these new power plants would balance the capital costs and minimize bill impacts, showing that overall fuel savings on power plant upgrades would yield a savings of $1 billion annually starting in 2014.

Studies, Reports, and Testimony

FP&L's request to extend the GBRA was opposed by the intervenors and the PSC staff. As summarized by the Office of Public Counsel, the GBRA would "[allow] FPL to create a base-rate adder for all generating plant that is placed in service between rate proceedings without the regulatory scrutiny that would normally be required for base rate adjustments." The PSC Staff recommended that the PSC should let the GBRA expire at the end of 2009 and examine cost recovery for any new power plants in a rate case that "provides for a more rigorous and thorough review of the cost and earnings associated with new generating units."

FP&L responded that the GBRA was not a radical departure from normal ratemaking as evidenced by its successful use over the past five years by FP&L as well as the use of a similar mechanism by Alabama Power Company that has been in place since 1982. FP&L also noted that if the GBRA was not extended, then ratepayers would still receive the benefit of reduced fuel costs from new, more efficient power plants but would not be required to pay for that benefit simultaneously. This would send an incorrect price signal and deny FP&L reasonable recovery on a prudent investment.

Final Determinations

The PSC denied FP&L's request to continue the GBRA, largely adopting the recommendations and rationale of the PSC Staff. The PSC concluded:

> The record shows that FPL already collects about 61 percent of its total revenues through various "pass-through" mechanisms and cost recovery clauses. We are not convinced that adding another such mechanism, by permanently implementing a GBRA for FPL, would provide advantages over traditional rate case procedures found in Section 366.06, F.S. We find no justification in the record for approving a cost-recovery mechanism for FPL's new generation that is different from what applies to all other investor-owned electric utilities. Approving a GBRA for FPL on a permanent basis would constitute a significant change in our general ratemaking policies.

FP&L and a number of intervenors filed motions for reconsideration, but the GBRA was not one of the issues challenged. However, over the course of settlement negotiations, cost recovery for West County Unit 3 entered into the discussions. During the proceedings, this Unit had already received a Need Determination and was projected to be completed in June 2011. Instead of allowing West County Unit 3 to utilize the GBRA, the parties agreed on a compromise where the capital costs of power plant could be recovered through an existing capacity charge once the unit was placed in service, but the total amount of recovery would be capped at the level of projected fuel savings from the plant.

Project Status

The three projects that would have utilized the GBRA have received positive Need Determinations and continue to move forward. West County Energy Center Unit 3 has begun start-up work and has finished fuel gas piping work. Current projections show that it is still scheduled to come online in June 2011.[46] The Cape Canaveral coal units were demolished in August 2010. The new plant is scheduled to come online in 2013. The Riviera Beach unit is scheduled for removal within the next six months and the new units are projected to come online in 2014.

Reflections

The use of the already-approved GBRA for new generation absent a typical PSC review process was controversial. FP&L was perhaps one step ahead of the PSC in seeking opportunities to add capacity, modernize the utility and shrink its carbon emissions – when mandatory carbon limits seemed imminent. The public, the intervenors, and the PSC reportedly felt that such a large

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[46] Dr. Robert Peltier. *Top Plant: West County Energy Center, Palm Beach County, Florida*. Power Magazine. Sept. 1, 2010. http://www.powermag.com/gas/Top-Plant-West-County-Energy-Center-Palm-Beach-County-Florida_2954_p3.html.

new investment needed to be vetted through the process of a full rate case. Typically, we would expect an initiative of this magnitude to be reviewed through a traditional rate case process, which was ultimately how it was resolved.

E. Georgia Case Study

The Georgia case study is noteworthy as the first attempt by a Georgia utility to use one of the more expedient cost recovery mechanisms. Not all of the Commissioners were comfortable with the innovation. However, the need for the utility to access capital without damaging its credit rating seemed to motivate the remainder of the Commission. The ability to find capital and reduce the impact of compliance costs on ratepayers could be a familiar theme as utilities advance new strategies to comply with EPA regulations, especially while the U.S. economy continues to recover.

Georgia Public Service Commission

The Georgia Public Service Commission was established in 1879 by the Georgia General Assembly for the purpose of regulating railroad passenger and freight rates, services and operations. As Georgia's population grew and industry expanded, the Commission undertook additional responsibilities through regulatory expansion and deregulation. Currently a variety of services and utilities are included under the Commission's jurisdiction.

The PSC consists of five elected Commissioners, supported by approximately 100 staff. The five Commissioners of the PSC are elected statewide and serve staggered six-year terms. On an annual basis, the chairman of the Commission is selected based on seniority.

Georgia operates under the SERC Reliability Corporation (SERC) region, which covers the bulk power system in 16 central and southeastern states. SERC is one of eight regional entities with delegated authority from NERC. SERC aims to propose and enforce reliability standards within the Southeast. SERC is divided geographically into five diverse sub-regions.

Georgia Rate Case Procedure

Within the Georgia PSC, the rate case filing process begins when the utility requests a rate increase, issues a public notice of intent, and files a rate case petition and a request for the proposed rates to take effect in 30 days. The Commission then reviews this petition and sets a hearing date.

Following the final session of public hearings, all parties review the transcript and file recommendations. At a subsequent administrative session, the Commissioners decide what, if any, rate increases to grant and when the new rates will go into effect. The Commissioners must make this decision within six months of the original filing date or the utility is legally entitled to 100 percent of its request, under bond and subject to refund. After a decision on the rate case, the Commission issues a final order. The new rates go into effect 165 to 180 days after the initial filing of the rate change request.

Georgia State Code on Public Service Commissions

Title 46 of Georgia State Code covers all state laws pertaining to Public Utilities. Section 46-2-23 states that the commission shall have exclusive power to determine what are just and reasonable rates and charges to be made by any person, firm, or corporation subject to its jurisdiction.[47]

According to Section 46-3A-10, when setting rates for a certificated capacity resource, the Commission shall consider changed revenues and changed risks, if any. The Commission's decision in any certification, recertification, modification, or construction review proceeding shall be based on evidence of record. The Commission's findings, although subject to judicial review, shall not be subject to relitigation in any other proceeding. However, the issuance of a certificate shall not preempt any local, state, or federal governmental body from the regulation of environmental or safety matters as a result of construction of electric generating plants.

Section 46-3A-7 addresses construction costs as part of a rate base, review of construction work in progress (CWIP), verification of expenditures, and recovery of costs of canceled construction. Upon the completion of plant construction, a utility can add costs to its rate base that do not exceed 100 percent of those approved by the commission. In addition, the commission may conduct, or the utility may request that the commission conduct, an ongoing review of plant construction as it proceeds. Every one to three years, the utility shall file a progress report and any proposed revisions in the cost estimates, construction schedule, or project configuration. Within 180 days of such filing, the commission shall approve these expenditures and any proposed revisions.

In addition, Section 46-3A-2 of the Georgia State Code includes all laws applicable to filing an Integrated Resource Plan (IRP) and obtaining a certificate of public convenience and necessity (CPCN) for power plant construction. Every three years, since 1992, utilities are required to file an IRP with the Commission. Within 120 days after the filing of each IRP, the Commission shall approve and adopt the IRP. A CPCN is required for construction of new generation and transmission, as well as for modifications to existing generating plants, but only if the modification increases or decreases generation capacity at the facility. A CPCN is not required for pollution control modifications.

Relevant Environmental Regulations

The environmental controls referenced in this case are required to comply with the Georgia Multipollutant Rule, the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule, and NAAQS for $PM_{2.5}$ and ozone.

The Georgia "Multipollutant Control for Electric Utility Steam Generating Units" rule was made final on June 27, 2007. The Georgia Environmental Protection Division (EPD) developed this rule

[47] Georgia State Code. Title 46. Chapter 2. Article 2. Section 23. 2011. http://www.lexisnexis.com/hottopics/gacode/Default.asp.

to address several air quality issues within the state. The EPD performed air quality modeling related to Atlanta being designated nonattainment with the ozone and fine particulate matter Air Quality Standards. This modeling showed that emissions from Plants Scherer and McDonough contributed to nonattainment. Therefore, while the Georgia EPD adopted the federal CAIR and CAMR regulations, they also developed the Georgia Multipollutant Rule to require specific emission control systems that will achieve reductions in mercury, SO_2, and NO_X emissions in Georgia. The Multipollutant Rule requires the installation and operation of specific air pollution control equipment on specified power plant units.

Summary and Chronology

This case study examines the rate case filed in 2007 by Georgia Power Company. This rate case established the Environmental Compliance Cost Recovery (ECCR) Tariff, which was designed to recover environmental compliance costs incurred by Georgia Power as a result of complying with federal or state environmental laws, regulations, or permit requirements.

In Georgia Power's previous rate case, in 2004, the PSC approved a three-year Accounting Order, to remain in effect through December 31, 2007. The PSC has issued Accounting Orders in Georgia Power's rate cases since 1996. An Accounting Order can prescribe financial mechanisms that aren't generally used in a traditional rate case, such as capping rates and determining how excess earnings should be accounted for.

This Accounting Order was approved in December 2007 with rates set to provide an 11.25 percent return on equity. As approved, the Order stated that beginning January 1, 2008, the Company shall increase its base rates by $100 million. The three-year term for this Order ended on December 31, 2010.

Within the 2007 rate case, Georgia Power filed for environmental cost recovery through the ECCR tariff at a number of its coal-fired power plants, including one plant with two units slated for retirement and natural gas retrofit in 2011 and 2012. The final Settlement Agreement approved the full amount of costs for the installation of environmental controls on Georgia Power's coal-fired plants, as well as cooling towers on the two units scheduled for retirement.

Facility Description

In the 2007 rate case filing, Georgia Power requested recovery of costs for scrubber, SCR, and baghouse installations at their Bowen, Hammond, Scherer, Wansley, and Yates plants. A breakdown of the environmental controls being installed at these plants is shown in Table 15, taken from an exhibit to the rebuttal testimony of Georgia Power's Ann P. Daiss.

Table 15. Projected Year-End Balances for Environmental Controls, 2007-2010

Plant Name	Environmental Controls	2007	2008	2009	2010
Bowen					
	Scrubbers	-	$609,091	$871,604	$1,064,446
	SCR Catalyst	$2,160	$2,160	$2,160	$2,160
Hammond					
	Scrubbers	-	$296,460	$296,460	$296,460
Scherer					
	SCRs	-	$6,000	$8,252	$99,331
	Baghouses	-	$114,031	$146,074	$146,667
Wansley					
	Scrubbers	-	$160,960	$289,101	$289, 101
	Monitors	$8,100	$18,891	$18,891	$18,891
Other Controls					
		$69,588	$184,832	$207,412	$222,762
Grand Total		$79,848	$1,392,424	$1,839,953	$2,139,817

Georgia Power also requested cost recovery of cooling towers for Plant McDonough Units 1 and 2. The Plant McDonough Units are two steam units with a combined capacity of 517 MW with coal-fired boilers that were installed in 1963 and 1964. Plant McDonough is located in Cobb County, near downtown Atlanta.

Georgia Power's original 2006/2007 Compliance Strategy for McDonough Units 1 and 2 included the construction of Selective Catalytic Reduction (SCR) equipment and a shared scrubber on both McDonough coal units to comply with the Georgia Multipollutant Rule, CAIR, CAMR, and the Clean Air Visibility Rule. However, due to the high cost of maintaining these units, the extensive environmental upgrades necessary, and environmental concerns involving emissions in Metropolitan Atlanta, in late 2006, Georgia Power proposed to retire Plant McDonough Units 1 and 2 and replace them with three 840 MW natural gas combined-cycle gas units by 2012. During the 2007 rate case proceedings, Georgia Power's proposal for retirement was in the process of being reviewed by the PSC in a parallel docket, and the proposal was granted on September 4, 2007.

Georgia Power's Vogtle Nuclear Plant Units 1 and 2 are also discussed in this case in terms of an extension of the operating license, and the recovery of decommissioning costs. Vogtle consists of two Westinghouse pressurized water reactor units located near Augusta, Georgia on the southwest side of the Savannah River. The site is in the eastern sector of Burke County, Georgia, and across the river from Barnwell County, South Carolina.

Description of Riders

Under the Settlement Agreement, effective January 1, 2008, Georgia Power was authorized to implement the ECCR Tariff. The ECCR tariff was levelized to collect $222.3 million annually between January 1, 2008 and December 31, 2010.

Cost Recovery Description

Environmental Cost Recovery

An issue of contention in this case was the disagreement between Georgia Power and PUC Advocacy Staff over the recovery of environmental costs outside the test year period. In a traditional rate case, a test year is used to determine the cost for the utility of doing business, and thus what its revenue requirements are. Georgia Power's filing based the company's revenue requirements on the twelve months ending July 31, 2008, with the exception of the ECCR, which included projected test year data to support multi-year revenue requirements related to environmental expenditures in 2009 and 2010.

The disagreement focused on whether it was appropriate to recover post-test year costs in the context of a rate case. However, because the case was resolved through a three-year Accounting Order as opposed to a traditional rate case proceeding, the PSC concluded that the environmental compliance costs incurred during the three-year term of the Accounting Order could be recovered through the ECCR tariff.

Commissioner Angela Elizabeth Speir filed a dissenting opinion to the final order in which she expressed concerns with the approach taken to the ECCR. Commissioner Speir asserted that the Commission erred in approving the recovery of projected environmental costs beyond the test year. Instead, she contended, these expenditures should be included in base rates through a new rate case (rather than automatically via a separate tariff) after the equipment was in service and costs could be determined to have been prudently incurred. In Speir's opinion, because the projected environmental costs "have not been (and will never be) certified by the Commission," they should not be eligible for recovery.

The PSC determined that the final Accounting Order was just and reasonable, and would provide benefits to consumers that would not be realized in a traditional rate case order. Under the Accounting Order, Georgia Power's return on equity was capped at 12.5 percent, and any earnings above this would flow to the benefit of ratepayers. In contrast, under a traditional rate case order, the Company could earn well in excess of a 12.5 percent return on equity without the ratepayers receiving any rate reductions. This type of accounting order also reduces regulatory lag for both the utility and ratepayers, because increased earnings are returned to customers right away, rather than in a subsequent rate case.

In addition, the Accounting Order would provide ratepayers with rate stability, as the Stipulation prohibits Georgia Power from filing for a rate increase until July 1, 2010. Under a traditional rate case order, the Company would be able to file another rate case whenever it deemed appropriate. The Commission highlights this aspect of an accounting order to justify its approach to the ECCR tariff. The environmental compliance costs that did not fall within the test year period for this case could have fallen within the test year period of a subsequent traditional rate case filing , and so it is fair to allow recovery of expenditures projected to occur within the three-year accounting order period.

The Order also instituted a true-up mechanism in the event that costs differed from the projections. If actual costs were higher than projected, then they could be recovered in a subsequent rate case if Georgia Power was earning below the mid-point of the earnings sharing band (11.25 percent). Conversely, if costs were lower than projected, a downward adjustment rate would be included in the next rate case if Georgia Power was earning at or above 11.25 percent. This allowed the PSC and Georgia Power to use the ECCR to balance earnings within a narrow band before resorting to a rate case to address the difference between actual and projected costs.

Nuclear Decommissioning Cost Recovery

In a supplemental order regarding Nuclear Decommissioning Costs, Georgia Power requested that the PSC issue an Accounting Order to confirm a new level of annual nuclear decommissioning expense to be included in the Company's cost of service. Therefore, within the Stipulation, effective January 1, 2008, Georgia Power will begin including in its cost of service an amount of annual decommissioning expense reflecting the cost necessary to decommission the radioactive portion of the nuclear units based upon the 2006 Nuclear Regulatory Commission's minimum funding requirements. The Stipulation allowed Georgia Power to recover the NRC minimum plus an adder for spent nuclear fuel storage.

Studies, Reports, and Testimony

Recovery of Environmental Costs

As previously mentioned, another issue of contention within the testimonies focused on the recovery of environmental costs outside the test year period, ending July 31, 2008, and whether it was appropriate to recover post-test year costs in the context of a traditional rate case proceeding. PSC Staff witness Robert J. Henkes recommended that the PSC disallow all post-test year environmental investments and expenses included by the Company for the post-test year period August 1, 2008 through December 31, 2008.

Base Rate Increases

Jeffrey Pollock testified on behalf of the Georgia Industrial Group (GIG) and the Georgia Traditional Manufacturers Association (GTMA) regarding Georgia Power's base rate increases. Members of these two groups are customers of Georgia Power Company and consume large quantities of electricity, primarily for manufacturing. Pollock stated that the proposed increase in rates will further disadvantage Georgia's manufacturers in relation to competition in the Southeast and overseas. Georgia Power's three-year rate plan calls for base rate increases of 4.5 percent effective January 1, 2009 and 1.0 percent increases effective January 1, 2010. Pollock testified that GIG and GTMA are recommending that the proposed January 1, 2008 base rate increase be cut back by at least $109 million and that further changes should be made to the proposed three-year rate plan that would offset the proposed 2009 and 2010 increases.

Studies

A study on plant depreciation was prepared by Charles W. King, president of the economic consulting firm Snavely King Majoros O'Connor & Lee, Inc. King testified on behalf of the PSC as an Advocacy Staff witness. Based on his study, King recommended that the expected life spans of Georgia Power's steam production plants be set at 60 years, rather than 55 years; that the expected life spans of the Vogtle nuclear units 1 and 2 be extended from 50 years to 60 years; and that the combined cycle turbine/steam plant life spans be set at 45 years rather than 35 years. These extensions of plant life expectancy adjust the depreciation rates for Georgia Power's facilities, but are not necessarily predictive of the retirement date for these plants. In his testimony, King also recommended that nuclear plant dismantlement costs should not be collected in depreciation rates, as there is a separate decommissioning fund for each of these plants that includes all dismantlement costs.

Public Hearings

In Georgia Power's 2007 rate case filing, there were a total of six hearings, held from October 1-3, 2007, and from November 5-7, 2007. There were also two post-hearing briefs. Intervenors in these hearings included primarily Public Interest Advocacy Staff of the Commission, as well as representatives from Georgia Power. Other intervenors in this proceeding included the Consumers' Utility Counsel Division (CUCD) the Association for Fairness in Rate Making, the Commercial Group, the Cable Television Association of Georgia, Georgia Municipal Association, Macy's Inc. f/k/a Federated Department Stores, the Georgia Electric Membership Corporation, the Georgia Industrial Group, the Georgia Traditional Manufacturers Association, Inc., the Kroger Company, Metropolitan Atlanta Rapid Transportation Authority, Resource Service Ministries, Resource Supply Management, Georgia Environmental Facilities Authority of the Division of Energy Resources, and the U.S. Department of Defense and All Federal Executive Agencies.

Final Determinations

The final Settlement Agreement approved that, effective January 1, 2008, Georgia Power would increase its base rates by $99.7 million and implement the ECCR Tariff. This is the full amount originally requested by Georgia Power's in its rate case filing. Based on testimony described above, the PSC removed the environmental costs embedded in the test year revenue requirements and included them in the ECCR tariff. The ECCR tariff was levelized to collect $222.3 million annually between January 1, 2008 and December 31, 2010

The final Settlement Agreement approved the full amount of costs for the installation of environmental controls on the company's coal-fired plants, as well as the McDonough Units 1 and 2 cooling towers.

Based on Charles King's testimony regarding his study on plant depreciation, the Settlement Agreement extended the Environmental Plant Life on plants receiving environmental controls from 55 to 60 years, and specifically extended the life of Georgia Power's Plant Vogtle from 50 to 60 years, as it is likely that the Nuclear Regulatory Commission will grant the application to renew the license for Plant Vogtle. In addition, the Stipulation includes a supplemental Commission order directing the Georgia Power to collect and remit funds for nuclear decommissioning with explicit instructions as to the qualified and non-qualified portions of those funds.

Project Status

In May 2010, the Georgia PSC voted to allow Georgia Power to defer the retirements of Plant McDonough units 1 and 2 for six months and one year, respectively.[48] According to Georgia Power, the delay will allow Georgia Power to reduce its upcoming rate case filing by approximately $250 million. The company proposed the delays because the current forecasted loads for 2011 and 2012 were lower than the loads forecasted in 2007, when the project was originally approved by the PSC. The load-forecast reduction is a result of the recent economic recession. In addition, the company proposed deferring the retirement of the existing coal units because there is still a need for generation at the site to maintain transmission reliability.

The two cooling towers at Plant McDonough, designed to reduce the thermal impact of water discharges into the Chattahoochee River, went online in 2008. When the coal-fired units are retired, the cooling towers will remain at the site for use with the four combined cycle units that are slated to replace them.[49]

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[48] Georgia Power. *PSC Approves McDonough Unit Delays*. News Release. May 2010. http://www.georgiapower.com/pluggedin/mcdonough_2010_05.asp.

[49] PR Newswire. *Plant McDonough Cooling Tower to Begin Commercial Operation, Will Improve Chattahoochee River Quality*. February 21, 2008. http://www.prnewswire.com/news-releases/plant-mcdonough-cooling-tower-to-begin-commercial-operation-will-improve-chattahoochee-river-quality-57080697.html.

According to Georgia Power, as of 2009, all four baghouses at the Scherer plant were expected to be in service by January 2010. The first scrubber at Scherer was expected to go into service in 2011, with the final one going online in 2014. At Plant Bowen, three scrubbers were already in service, and the fourth one, on Unit 1, was scheduled for early 2010. A second scrubber at Plant Wansley was commissioned in spring 2009. Construction of the SCRs and scrubbers at Plant Branch and Plant Yates was scheduled to begin in 2011, with the equipment coming online by 2014.[50]

Reflections

Georgia Power's 2007 rate case filing represents the first time that projected environmental costs at the company's generating facilities were addressed in an expeditious way using an environmental cost recovery mechanism, the ECCR tariff. Despite contention surrounding the inclusion of environmental costs outside the test year, the ECCR tariff was approved by the Georgia PSC and was continued and enhanced in Georgia Power's 2010 rate case.

The rate case examined in this case study revealed less specific information than other case studies. Certain background documents that would have provided beneficial information were not available in the online docketing system. Specifically, a parallel docket concerning the retirement of McDonough Units 1 and 2 was explored, but many of these documents were not available to the public online. However, the 2010 rate case offers the public more access to the documents in the docket than the 2007 rate case.

This case was unlike others we examined in that there was little public opposition expressed in the testimony relating to the retirement of the coal-fired McDonough Plant Units 1 and 2, or the planned natural gas retrofit of these units. Based on the testimony included in the rate case docket, replacing coal-fueled McDonough Units 1 and 2 with natural gas-fueled combined cycle generating units was accepted as a more cost-effective option than retrofitting the plant with environmental controls. However, as previously mentioned, the examination of other unavailable documents may have granted more information on this topic. It is also possible that any opposition to the retirement of these coal-fired units was offset by the extensive pollution control installations occurring simultaneously at Bowen, Branch, Hammond, Scherer, Wansley, and Yates plants. According to Georgia Power's testimony, approximately 90 percent of Georgia Power's coal generation capacity will have controls installed by the end of the program, and the construction workforce projected for these projects was expected to total over 2,000 workers.

[50] Georgia Power. *Georgia Power Investing Nearly $2.8 Billion in Georgia during 2009*. News Release. August 2009. http://www.georgiapower.com/pluggedin/construction_2009_08.asp.

F. West Virginia Case Study

This case study compares and contrasts two different approaches that have been employed in West Virginia to pay for and recover the costs of pollution control retrofits. One case involves a classic rate case, while the other examines a relatively new financing option: securitization. Securitization is the use of ratepayer-backed bonds to finance a pollution control project, instead of traditional utility financing. This case study is therefore divided into two Parts. Part I examines a classic rate case; Part II looks at the use of securitization to finance emission reduction investments.

West Virginia Public Service Commission

The West Virginia Public Service Commission (PSC) supervises and regulates the rates, services, operations and other activities of public utilities within West Virginia. The PSC acts upon petitions filed by these regulated entities, and complaints filed against them. The PSC was created in 1913 by the West Virginia State Legislature to regulate railroads, and since then has expanded to regulate companies providing electricity, natural gas, water, telecommunications, and sewer service in all fifty-five counties of the State.

The West Virginia PSC consists of three members who are appointed by the Governor with the advice and consent of the Senate. No more than two commissioners may belong to the same political party. Each commissioner serves six-year staggered terms, with one term expiring July 1 of each odd numbered year. In addition, one commissioner is designated as Chairman of the PSC by the Governor and serves as the chief administrative officer of the Commission.

West Virginia operates under the PJM Interconnection. PJM is the world's largest wholesale electricity market, and serves as the regional transmission organization for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Relevant Environmental Regulations

The modifications proposed by Appalachian Power Company were designed as a compliance strategy in anticipation of emissions reduction requirements for SO_2, NO_X, and mercury in EPA's CAIR and CAMR rules.

Part I. Examination of Classic Rate Case in WV PSC

Summary and Chronology

Appalachian Power Company (APCo)[51] sought to recover the costs of, among other items, a $1.2 billion scrubber retrofit program. While the parties to the case agreed that APCo was generally entitled to cost recovery for controls needed to comply with the Clean Air Interstate Rule (CAIR), they differed over the manner of recovery: APCo wanted recovery approved in advance without

[51] APCo also includes Wheeling Power Company.

review of actual costs, while the West Virginia Public Service Commission (PSC) and intervenors pressed for recovery of future costs in a future rate case or, at a minimum, through an annual cost recovery mechanism that allowed for the review of actual costs. Ultimately, the parties settled on recovery of Construction Work in Progress on an annual basis after a review of the costs.

The rate case lasted 11 months and illuminates how stakeholders can be willing to balance concerns about higher rates with the reality that pollution control investments can be extraordinary investments requiring innovative recovery mechanisms.

Facility and Modification Description

American Electric Power Company (AEP) conducted a system-wide review of its power plants to develop a company-wide compliance strategy with CAIR and CAMR. Anticipating cuts in SO_2 allowances of as much as 50 percent, AEP and its subsidiary Appalachian Power Company (APCo) proposed to install flue gas desulfurization systems (FGDs or "scrubbers") on four units at two coal-fired power plants: Mountaineer and John Amos Units 1, 2 and 3. The units have a combined capacity of 4,200 MW (over 50 percent of APCo's power generation capacity), and are summarized in Table 16.

Table 16. Plant Characteristics for APCo Scrubber Projects

Name	Capacity (MW)	Planned FGD In-Service Date
Mountaineer	1300	January 2007
John Amos 1	1300	January 2009
John Amos 2	800	January 2009
John Amos 3	800	January 2008

APCo's Cost Recovery Request and Legal Basis

APCo estimated total cost for the projects was $1.27 billion, of which approximately 45 percent, or $577 million, was allocated to APCo's West Virginia operations. Historically, cost recovery for capital projects in West Virginia follows the traditional model: recovery is deferred until the project is in service and a new rate case is filed to recover the costs. However, given the extraordinarily high level of investment and the infrequency of general rate cases in West Virginia (as of August 2005, APCo's base rates had not increased for 20 years), APCo was concerned about the impact that regulatory lag would have on timely cost recovery. The costs of the scrubber projects, when completed, would add $83 million annually to the overall revenue requirement used to calculate rates. However, APCo would not be able to add the additional revenue requirement to customer rates until the scrubber projects were complete and a new case filed and approved. Such a delay was not acceptable for the level of investment, according to the rebuttal testimony of Terry R. Eads on behalf of APCo:

> "In the context of an ordinary rate case and its timing, there can be compensating factors, such as decreasing costs offsetting increasing costs, or increased revenues not reflected in current rates balancing increased costs not reflected. Here we are dealing with non-revenue-producing costs which are so large that nothing can offset or balance them. Some appropriate mechanism beyond the ordinary methods used for ordinary costs in ordinary circumstances is needed to deal with them."

In order to recover its costs in a more timely fashion, APCo filed a general rate case on August 25, 2005. Because the scrubber projects were not yet completed, APCo did not include them in the core rate base calculations. Instead, APCo requested a special surcharge that would allow automatic recovery of scrubber project costs without filing a new rate case. Essentially, the additional revenue requirements created by the scrubber projects would be recovered through a special surcharge on the demand portion of each customer's bill. The surcharge would be adjusted upward annually from 2007 through 2009, reflecting the projection that new scrubbers would be in service each of those years and therefore eligible for recovery (see Table 17).

Table 17. Projected Additional Revenue Requirements for Scrubber Projects, 2007-2009

Plant	2007	2008	2009
Mountaineer	$34,507,573	$33,841,175	$33,179,308
Amos Unit 3	-	$10,569,866	$10,354,984
Amos Unit 1&2	-	-	$39,433,173
Total	**$34,509,580.00**	**$44,413,049.00**	**$82,969,474.00**

APCo based its departure from normal cost recovery procedures on a West Virginia statute that says, in part:

> (b) Upon a finding that it is in the public interest of this state, as provided in section one, article one of this chapter, the public service commission shall authorize rate-making allowances for electric utility investment in clean coal and clean air technology facilities or electric utility purchases of power from clean coal technology facilities located in West Virginia which shall provide an incentive to encourage investments in such technology ...
>
> (d) The public service commission shall determine, at such time and in such proceeding, form and manner as is considered appropriate by the commission, the extent to which

> any electric utility investment or purchases of power qualify for incentive rate-making pursuant to this section. W.Va. Code 24-2-18.

APCo contended that the "value that these investments bring to the State and its economy in terms of capital investment and employment opportunities, both from the utility operations themselves and from the mining sector that supplies the coal to be burned, clearly justifies special rate consideration under the statutory warrant. Moreover, encouragement of these investments will achieve significant benefits to the general public in terms of improving environmental quality both within and outside the state."

Studies Reports and Testimonies

APCo's proposal was roundly criticized by staff of the PSC, major intervenors and the Consumer Advocacy Division (CAD). In their report, the PSC staff flatly rejected the proposal, stating:

> "Staff is not in agreement at all with the Companies' request for estimated and future rate making treatment pertaining to the scrubbers. Staff recommends that the scrubber costs and investments be reviewed in some type of future rate proceeding if needed by the Companies if, and when, the actual costs are known and in service. To do so otherwise would be improper rate making treatment."

Intervenor Kroger Co., owner of a chain of grocery stores in the state, summarized the two core objections. First, APCo's request was not prudent because it would result in "single-issue ratemaking." This occurs when a single cost item is permitted to impact rates in isolation from all other rate considerations. As a result, changes in other costs and revenues are not taken into consideration, creating a situation where APCo could earn an overall return that is above or below the return approved in the rate case.

Second, APCo's request was not reasonable or prudent because it would approve the amounts of cost recovery in advance, without a mechanism for reviewing and adjusting recovery for actual costs. According to Kroger, differences between projected and actual costs would only be addressed in a future rate proceeding on a prospective basis. As a result, "customers have no assurance that the investments they are being asked to fund would be built on the same schedule presumed in the charges that are being proposed. Exposing customers to such a potential mismatch between cost and benefit is not in the public interest."

The CAD echoed these concerns in its testimony. However, unlike the other intervenors, the CAD agreed that the extraordinary costs of the scrubbers required some form of accelerated cost recovery. In order to address issues about single-issue ratemaking and the inability to review actual costs before new rates were imposed, the CAD proffered a compromise in which APCo would be able to recover Construction Work in Progress (CWIP) costs through an annual surcharge. The amount of the surcharge would be subject to review and approval by the PSC and the public annually as part of the review of the company's expanded net energy cost recovery mechanism.

Final Determinations

On July 26, 2006, the PSC approved a settlement of the general rate case. With respect to the recovery of pollution control costs, the parties agreed to accept the compromise offered by the CAD, with minor modifications, to allow accelerated recovery via a demand surcharge. APCo further agreed to file a general rate case in 2010 and, as part of that filing, move all completed projects formally into rate base as a further way to address the single-issue ratemaking issue.

Project Status

Three of the four scrubber projects have been completed: the Mountaineer Plant retrofit was finished in 2007, Amos Unit 3 was completed in March 2009, and Unit 2 in February 2010. Unit 1 is expected to go into service in early 2011. In its most recent filing, the pollution control projects added approximately $76.5 million to the revenue requirement, about $6.5 million less than originally projected. This is largely driven by the fact that Unit 1 has not yet been completed. This indicates that the concerns of the stakeholders were valid – the original cost recovery requested by APCo would have, in fact, been too high. At the same time, when Unit 1 is completed, the total revenue requirement will likely end up higher than projected (if the costs are similar to Unit 2), lending weight to APCo's position that it was bearing as much risk as its customers. In the end, the case study demonstrates that the compromise reached by the parties through the PSC process achieved the intended result: allowing accelerated recovery of extraordinary expenditures for APCo, while prudently protecting the interests of APCo's customers.

Part II. Examination of Securitization Case in the WV PSC

Under the traditional utility financing model, a utility will pay for a major capital project through a mixture of two sources: debt and equity. Once the project is included in the rate base, the utility will earn a return on capital that covers the interest on the debt and provides for a return (profit) on the equity. The return that is required to cover the debt and equity is the "cost of capital."

Securitization as an alternative financing mechanism is the practice of paying for a capital project outside of the utility financing model by selling bonds that are directly backed and paid for by ratepayers. The bonds are "secured" by the pollution control equipment and an irrevocable promise that ratepayers will make the payments on the bonds through a dedicated charge on their bills. Utility shareholders provide no separate guarantee. The ratepayer guarantee, enforced by statute and the terms of the financing, minimizes the risk of default, and the resulting interest rate should be significantly lower than either the interest on debt incurred by utilities or a utility's return on equity. Thus, the cost of capital using securitization can be significantly lower than the traditional utility cost of capital.

While securitization can provide cheaper capital, it can also pose unique risks to ratepayers, because they are providing funding for a project up front instead of after completion or at regular stages of development. Once the bonds are issued, the ratepayers are on the hook financially no matter what happens with the project. Accordingly, ratepayers have no recourse if the investment turns out to be a poor one.

Moreover, securitization leaves the utility out of the profit earning equation. While this means that securitization will not always be a favored financial tool for utilities, it can be useful in situations where a utility's financial position prevents it from raising capital for high-cost projects.

West Virginia Code: Securitization Statute

In April 2005, the West Virginia Legislature passed a law authorizing utilities to issue "Environmental Control Bonds" (ECBs): bonds dedicated to financing pollution control projects at the state's coal-fired power plants.[52] The Legislature found that electric utilities in the state needed to install and construct emission control equipment at generating facilities in the state in order to meet the requirements of existing and anticipated environmental laws and regulations. However, the financial condition of some electric utilities made the use of traditional utility financing mechanisms to finance the construction and installation of emission control equipment difficult or impossible.

To avoid deferment of the installation of emission control equipment, high financing costs, or a shift away from "high-sulfur coal mined in the State," the Legislature provided for securitization of pollution control projects through the issuance of ECBs. The statute permits a utility that is applying for a Certificate of Public Convenience and Necessity (CPCN) to install pollution control equipment to also apply for a "Financing Order" to issue bonds that will fund the project. The Financing Order authorizes the utility to levy an environmental control charge to make payments on the bonds. The authorization to levy the charge is an irrevocable until the obligation to bondholders is completely discharged.

In order to obtain the financing order, the utility must, among other things:

- Describe the environmental control activities and demonstrate that they are necessary and preferable to any other alternative; and
- Demonstrate that the environmental control costs are reasonable and the issuance of environmental control bonds will "result in overall costs to customers of the qualifying utility that [are] lower than would result from the use of traditional utility financing mechanisms."

Once a utility files for a financing order, the PSC is required to render a decision within 270 days.

[52] West Virginia State Code. Chapter 24. Article 2. Section 4e. Environmental Control Bonds. 2010. http://www.legis.state.wv.us/WVCODE/Code.cfm.

Summary and Chronology

In 2005, Allegheny Power filed for a CPCN for the installation of a scrubber at the Ft. Martin generating station. At the same time, they filed a request with the West Virginia PSC to authorize the issuance of $382 million in Environmental Control Bonds to pay for the project. The bonding mechanism had been created by the West Virginia Legislature to encourage investment in pollution controls at the lowest possible cost to ratepayers. After stakeholder negotiations, the PSC approved a settlement allowing Alleghany Power to issue $365 million in Environmental Control Bonds. The process took less than 11 months. Over the subsequent four years, the bonding authority was raised twice to a final number of $566.6 million. Allegheny Power and the PSC estimate that securitization saved ratepayers between $130 and $170 million.

Facility Description

The Fort Martin plant is a 1,107 MW coal-fired facility in Maidsville, West Virginia. The facility is comprised of two units: Unit 1 has a capacity of 552 MW and Unit 2 a capacity of 555 MW. In 2003, Ft. Martin Unit 1 emitted over 56,000 tons SO_2 in 2003; making it the 10^{th} highest emitter in the U.S., and Ft. Martin Unit 2 emitted over 45,000 tons, making it the 21^{st} highest emitter in the U.S.

Modification Description: Alleghany Power's Proposal, Response and Settlement

Alleghany Power was the first utility to take advantage of the new financing option, filing for a CPCN for a scrubber at its Fort Martin plant on March 24, 2005 and then filing for a financing order on May 24, 2005. Allegheny Power determined that a scrubber was the most effective way to meet its expected obligations under CAIR and CAMR while also maximizing local economic benefits.

Allegheny Power estimated total project costs of $338 million and proposed to issue $382 million in ECBs. The additional $42 million was based on projected financing costs. However, the proposal did not include separate caps for project costs and financing. As a result, if the financing costs were lower than projected, the remainder could be used to cover cost overruns.

Studies, Reports and Testimonies

In general, the proposal was not controversial: the CPCN and choice of using a scrubber were not contested, nor was the financing mechanism, since it had been expressly authorized by the Legislature. However, stakeholders such as the Consumer Advocate Division (CAD) asked the PSC to put in as many controls as possible to limit ratepayer exposure and maximize the benefits of using securitization by limiting financing costs. According to the direct testimony of Scott J. Rubin on behalf of the CAD:

> [T]he companies' proposal lacks these fundamental protections. As they propose the securitization, the Commission would determine the prudence of the project today (which is consistent with the CPCN process in West Virginia), but there would be no

> further review of the companies' actual procurement and construction. Similarly, under the companies' proposal, once the Commission approves the securitization order in these cases, customers would be obligated to repay the bonds without regard to the future used and useful nature of the facilities constructed. That is, under the companies' proposal, there would be nothing to provide a check on the companies' subsequent activities in design, construction, and procurement of the scrubbers.

The CAD requested that the PSC cap the bonds at $355 million, with a $338 million cap on project costs and a $17 million cap on financing costs. If costs exceeded the caps, then Allegheny Power would be required to either self-finance the additional costs and seek recovery through a rate case or file for a new Financing Order. The CAD also recommended that the PSC retain a financial advisor to oversee the bonding process and ensure that the financial costs were minimized.

<u>Final Determinations</u>

The parties reached a settlement on January 11, 2006, largely agreeing along the lines of the CAD's proposal, with a cap on project costs of $338 million, a cap on financing costs of $27 million, and the retention of a financial advisor to guide the PSC in its oversight. In approving the settlement on April 7, 2006, the PSC found that that the use of a "wet scrubber will sharply reduce the Applicants' reliance on emission allowances, providing a less volatile environmental compliance mechanism for the Applicants" and underscored the need for extensive oversight over the securitization process and the integral decision-making role that the PSC and its Financial Advisor would play:

> The Commission will act through its designated personnel and a financial advisor (the "Financial Advisor") to participate in all aspects of the structuring, marketing, and pricing of the Environmental Control Bonds and will make the decision, in conjunction with the Applicants, as to whether Environmental Control Bonds will be issued.

By taking an active, informed role the PSC sought to ensure that risks to ratepayers would be minimized and the benefits of securitization – low financing costs – would be maximized.

<u>Project Status</u>

Construction on the project commenced in September 2006, with a projected completion date of November 21, 2009. On October 3, 2006, Allegheny Power petitioned to reopen the case based on new engineering estimates that placed project costs at $550 million. Accordingly, Allegheny asked for authority to issue bonds for up to $573 million (including $23 million in financing costs). After negotiations, the parties to the case settled on, and the PSC agreed to, increasing Allegheny's authority to $466.5 million – $450 million for project costs and $16.5 million for financing costs. On April 11, 2007, the parties announced a successful $459.3 million bond offering that would save ratepayers an estimated $130 million over traditional utility financing.[53]

On July 1, 2009, Allegheny again petitioned to reopen the case stating that the cost estimate remained $550 million and that seeking cost recovery through traditional means (a rate case) would not be in the best interests of ratepayers because it would require Allegheny Power to issue its own debt on unfavorable terms. The parties again reached settlement and the PSC approved another $105 million in Environmental Control Bonds. On December 23, 2009, an additional $85.9 million in bonds were issued.[54] On February 4, 2010, Allegheny announced the completion of the Fort Martin scrubber project.

Reflections

APCo's 2005 rate case lasted 11 months and illuminates how stakeholders can be willing to balance concerns about higher rates with the reality that pollution control investments can be extraordinary investments requiring innovative recovery mechanisms. Allegheny's 2005 CPCN filing demonstrates how a relatively new concept for funding a pollution control project, securitization, can be successfully used. It required clear direction and a promise that ratepayers would repay the debt from the West Virginia legislature, along with clear deadlines to ensure that the process did not become delayed. Success also required that stakeholders were willing to compromise and move constructively on an expedited basis. Even though Allegheny Power went back to the PSC twice for authority to issue additional bonds, the requests in both instances were approved in approximately three months. In exchange for the expedited process, Allegheny Power continued to move forward on the project despite the financial uncertainty, and the other stakeholders cooperated with the accelerated process. As a result, the project was completed nearly on schedule at a much lower cost to the ratepayers. This case further demonstrates how securitization can help overcome financing obstacles faced by financially troubled utilities in a way that can reduce overall costs to ratepayers. It also shows that this new tool may require multiple PSC processes to set the right level of bonding authority, and that West Virginia's use of clear legislative directions and mandatory deadlines for PSC decisions were important in keeping project financing on pace with project development.

[53] West Virginia Public Service Commission. *Public Service Commission Of West Virginia (PSC) Projects $130 Million In Savings For Ratepayers Through Innovative Bond Sale*. April 11, 2007. http://saberpartners.com/press/pressreleases/pr_04_12_07.html.
[54] Allegheny Energy 10-K, March 1, 2010.

CONCLUSIONS

This study demonstrated that the PUC process is indeed influential in determining how utilities implement environmental compliance strategies. Many of the examples show changes to the timing or type of control installations eventually installed. Utilities' initial financial requests were often modified due to intervenors' positions and studies. Thus, PUCs are important institutions in shaping compliance solutions and will continue to be as utilities plan for compliance with the upcoming Utility MACT and Transport Rule. A deeper understanding of PUC procedures is useful and timely.

We examined 101 PUC processes that involved an approval prior to construction. The majority were completed within six months. This subset of observations is not conclusive, but it does indicate that most pre-construction PUC approvals can be processed within a year. These results are illuminating as the timeframes for compliance with EPA's new regulations are constrained by the text of the relevant Act and, in some cases, consent decrees.

EPA recently agreed in a consent decree to propose GHG NSPS and emission guidelines for power plants by July 2011 and finalize them by the end of May 2012. In addition to establishing a floor for GHG BACT, these performance standards will likely establish the first GHG standards for existing sources. To what degree the performance standard will be examined or altered by PUCs is unclear, given that EPA has not proposed the basis for such a standard or the flexibility options that it may allow. EPA has signaled that regulators should prioritize energy efficiency for the current GHG BACT determinations for new and modified sources. BACT permits may specify a maximum emissions rate and/or other performance criteria, and the generator must then select the most appropriate suite of control measures to attain the BACT limits. Energy efficiency upgrades to power

Indiana Case Study: PUC Influence on a Performance-Based Strategy

As discussed in the Indiana case study, Indiana generators were faced with a performance-based regulatory limit, in this case a tonnage cap on mercury emissions, and had several compliance options available including purchasing additional allowances to cover anticipated emissions or reducing emission through post-combustion controls and/or fuel switching. The Indiana PUC chose not to approve the utility's planned mercury controls, instead approving the purchase of sufficient allowances. However, with CAMR's vacatur in 2008, these plants remain uncontrolled for mercury. This case illustrates the current tension inherent in the PUC's mandate to minimize immediate rate costs. In retrospect, had the PUC approved the controls plan, the PUC would have approved expenditures and related cost recovery for a regulation that never took effect. On the other hand, the utility is now continuing to operate plants with no mercury controls installed. Additionally, had the utility controlled for mercury as planned, it would likely be well-positioned to meet upcoming requirements, including the Utility MACT. However, would Indiana ratepayers have paid more per pound of mercury removed, since the technology has advanced somewhat in recent years? Now the utility is forced to plan anew for regulations that have been known to be forthcoming. This case study, as well as the Florida case study to a degree, illustrates the hurdles utilities face in comprehensively addressing upcoming regulatory, legislative, and public mandates to transform the generation fleet.

plants can take many forms. Thus, it is hard to predict when an energy efficiency upgrade will be subject to a PUC determination. As demonstrated in the case studies, each PUC is unique. Some PUCs may require that an energy efficiency upgrade have a CPCN; others may not. In some cases, an upgrade may have a significant and distinct capital cost, while in other cases, it may be within a maintenance budget and be considered general practice by the utility and regulators. Given the wide range of potential upgrades and the variability among PUC requirements, it is difficult to generalize about the intersection of the two. A more careful review of energy efficiency upgrades, including their nature, size, and expense, could help gauge the likelihood that a PUC determination would be triggered.

Appendix A. Role of National Umbrella Organizations: NARUC and NASUCA

National Association of Regulatory Utility Commissioners

The national organization that brings all the PUCs together is called the National Association of Regulatory Utility Commissioners (NARUC). It was founded in 1889, as a nonprofit organization composed of governmental agencies engaged in the regulation of utilities and carriers (communications, energy, and water utilities) in the fifty states, the District of Columbia, Puerto Rico, and the Virgin Islands. NARUC represents the interests of state public utility commissions before the three branches of the Federal government, and its membership is composed of state public utility commissioners.

NARUC participates in several collaborative federal efforts with FERC and the Federal Communications Commission (FCC), including: 1) the Competitive Procurement Collaborative, which provides state and federal policymakers with a venue to discuss the best ways to meet the challenges of developing new and economical power supplies; 2) the Demand Response Collaborative, which serves to explore how federal and state regulators can better coordinate their respective approaches to electricity demand response policies and practices; and 3) the Smart Response Collaborative, to facilitate the transition to a smart electric grid.

Programs are operated by the NARUC Grants & Research Department, which receives funding from several Federal agencies, including the Environmental Protection Agency, the Department of Energy, and the Department of Homeland Security. Recent EPA funding to NARUC has been between $50,000 and $100,000 per year. The primary focus of the funding goes to educating commissioners about the specifics of energy efficiency policies. This amount of funding is a fraction of the amount the Department of Energy gives to NARUC.[55] Domestic programs are conducted with those agencies along with the New York State Energy Research and Development Agency and the Energy Foundation. In addition, NARUC's research foundation, the National Regulatory Research Institute, regularly releases papers on these and other subjects.

National Association of State Utility Consumer Advocates

The National Association of State Utility Consumer Advocates (NASUCA) is an organization that represents the interests of utility consumers. NASUCA consists of 44 consumer advocates in 40 states and the District of Columbia. The members of NASUCA are designated by the laws of their respective jurisdictions to represent utility consumers before state and federal regulators and in the courts. The founders of NASUCA established the organization for state agencies to act as independent ratepayer advocates. NASUCA's original purpose was to provide a forum to exchange ideas, improve consumer representation at the state and federal levels, and encourage greater consumer participation in the regulatory process. Currently, state consumer

[55] Call on November 10, 2010 with Joe Bryson, EPA and EPA Grants Award Database. http://yosemite.epa.gov/oarm/igms_egf.nsf/HomePage?ReadForm.

advocates focus on consumer protection issues, such as service quality, reliability, and price stability.

NASUCA’s seven standing and ad-hoc committees develop the policy positions that guide the organization’s advocacy activities and other programs NASUCA’s committees include: the Officers & Executive Committee, the Electricity Committee, the Telecommunications Committee, the Natural Gas Committee, the Water Committee, the Consumer Protection Committee, and the Tax and Accounting Committee.

APPENDIX B. NERC RELIABILITY

Table I. Sample of NERC Reliability Standards and Applicability

Reliability Standard	Purpose	Applicability
Real Power Balancing Control Performance	To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.	Balancing Authorities
Disturbance Control Performance	The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load, and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.	Balancing Authorities, Reserve Sharing Groups, Regional Reliability Organizations
Contingency Reserves	Contingency Reserve is required for the reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.	Balancing Authority, Reserve Sharing Group
Operating Reserves	Regional Reliability Standard to address the Operating Reserve requirements of the Western Interconnection.	This criterion applies to each Responsible Entity that is (i) a Balancing Authority or a member of a Reserve Sharing Group that does not designate its Reserve Sharing Group as its agent

Reliability Standard	Purpose	Applicability
Sabotage Reporting	Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.	Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, Load Serving Entities.
Cyber Security — Critical Cyber Asset Identification	NERC Standards CIP-002-2 through CIP-009-2 provide a cyber-security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System. These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed. Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets. Standard CIP-002-2 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.	Reliability Coordinator, Balancing Authority, Interchange Authority, Transmission Service Provider, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, Load Serving Entity, NERC, Regional Entity.
Generator Operation for Maintaining Network Voltage Schedules	To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.	Generator Operator, Generator Owner.
Data From the Regional Reliability Organization Needed to Assess Reliability	To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.	Regional Reliability Organization

Reliability Standard	**Purpose**	**Applicability**
System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements	System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.	Planning Authority, Transmission Planner
Response to Transmission Limit Violations	To ensure Transmission Operators take actions to mitigate (System Operating Limit) SOL and Interconnection Reliability Operating Limit IROL violations.	Transmission Operators
Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.	Transmission Operators, Reliability Coordinators
Monitoring System Conditions	To ensure critical reliability parameters are monitored in real-time.	Transmission Operators, Balancing Authorities, Generator Operators, Reliability Coordinators.
Transmission Operations	To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.	Transmission Operators
Planned Outage Coordination	Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.	Generator Operators, Transmission Operators, Balancing Authorities, Reliability Coordinators

Reliability Standard	**Purpose**	**Applicability**
Reliability Responsibilities and Authorities	To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.	Balancing Authorities, Transmission Operators, Generator Operators Distribution Providers, Load Serving Entities
Capacity Benefit Margin	To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.	Load-Serving Entities, Resource Planners, Transmission Service Providers, Balancing Authorities, Transmission Planners, when their associated Transmission Service Provider maintains CBM
Reliability Coordination — Transmission Loading Relief (TLR)	The purpose of this standard is to provide Interconnection-wide transmission loading relief procedures that can be used to prevent or manage potential or actual SOL and IROL violations to maintain reliability of the Bulk Electric System.	Reliability Coordinators, Transmission Operators, Balancing Authorities.
Reliability Coordination — Responsibilities and Authorities	Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a Reliability Coordinator delegates tasks to others, the Reliability Coordinator retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another.	Reliability Coordinators, Regional Reliability Organizations, Transmission Operator, Balancing Authorities, Generator Operators. Transmission Service Providers, Load-Serving Entities, Purchasing-Selling Entities.

Reliability Standard	Purpose	Applicability
Glossary of Terms: **Balancing Authority:** The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. **Load-Serving Entity:** Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers. **Regional Reliability Organization:** 1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate, and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor. **Reliability Coordinator**: The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. **Transmission Operator**: The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.		

APPENDIX C. DETAILS OF STATES FOR TIMING ANALYSIS

Alabama. Only investor-owned utilities are regulated by the Alabama PSC, thus Alabama Power is the only utility that falls under their jurisdiction. Alabama Power submits an annual environmental compliance plan associated with the Rate CNP portion of their rates. The Rate CNP is adjusted annually for cost recovery for, among other things, environmental compliance costs in the coming year. The PSC has final jurisdiction over approving this adjustment, but does not evaluate particular compliance strategies for their prudence or cost-effectiveness; decisions on compliance methods are left to Alabama Power and the Alabama Department of Environmental Management. The PSC's involvement in the approval of environmental upgrades and costs is short and perfunctory, and consists only of an annual informal meeting. Because of the PSC's limited involvement, and the fact that there is no formal approval of the environmental costs, Alabama was not included in the timing analysis.

Colorado. A number of different types of cases in Colorado have been used to approve pollution control projects and their cost recovery. In 1998, the Colorado legislature passed a bill encouraging utilities to enter into voluntary agreements with the Colorado Division of Public Health and the Environment to reduce emissions below those required by law. This law, codified as 40-3.2-102, C.R.S., allows utilities to recover the costs of implementing these agreements. In 1998, Public Service Company of Colorado (PSCo) entered into a voluntary emissions reduction agreement under this law and was granted cost recovery in a Commission order approving the plan. In 2005, PSCo entered into a settlement agreement regarding construction of a new coal-fired unit at their Comanche plant; the settlement agreement required them to install pollution controls on the existing units at Comanche and allowed them cost recovery for the controls. Finally, in 2010, PSCo filed a plan to comply with the state's new Clean Air-Clean Jobs act. Approval of the plan included granting a presumption of need for future CPCNs for the pollution control projects, as well as permission to accumulate AFUDC for recovery in a future rate case. This example is further explored as a case study in Section IV.

Florida. Utilities in Florida can recover the projected costs of environmental compliance through an environmental charge known as the Environmental Compliance Recovery Clause (ECRC). The level of this charge is set in an annual proceeding, and past recovery is trued-up to actual costs. Utilities must receive approval for any new projects to be included in the ECRC; they often do this in the course of the annual ECRC proceeding, but can also file separate cases to do so. The disconnect between a Florida utility and the PUC is explored as an example in Section IV.

Georgia. Georgia has no process outside of rate cases to approve environmental projects or cost recovery. However, in its 2007 rate case, Georgia Power established a separate rider for recovery of projected environmental costs, the Environmental Compliance Cost Rider (ECCR). The rate case set a value for recovery over the following three years. The ECCR was updated in Georgia Power's 2010 rate case to reflect the next three years of projected costs. Georgia Code

§ 46-3A-7 requires the PSC to decide rate cases within six months, thus both of these cases were resolved within that time period. A Georgia rate case is included as a case study in Section IV.

Illinois. Illinois is a deregulated state, and the price of electric generation is set by the market rather than the PUC. No CPCN is required for the construction of pollution control retrofits.

Indiana. In Indiana, utilities are required to obtain a CPCN from the Indiana Utility Regulatory Commission before installing "clean coal technology," i.e., emissions controls for NO_X or SO_2, at a generating facility. Utilities can also apply for a pollution control add-on at a coal plant to be considered "qualified pollution control property" (QPCP) and thus eligible to be added to the value of the facility for ratemaking purposes. At the same time, utilities can receive pre-approval for Construction Work-In-Progress (CWIP) ratemaking treatment, cost recovery for capital costs and operations and maintenance, and special accounting treatment for the project.

Our analysis included eleven cases involving CPCN, QPCP, and other ratemaking determinations made prior to construction of emissions-control retrofits. All cases except for one took less than a year. One case took more than two years; this case and some reasons for its length are described in the Indiana Case Study (Section IV).

Kentucky. Kentucky has both mandatory and optional pre-approvals for environmental projects. First, Kentucky requires a CPCN for construction of any "plant, equipment, property, or facility" involved in supplying electricity, which includes pollution control equipment. Second, utilities can submit an environmental compliance plan (ECP) for approval to the Kentucky PSC, which allows them to implement an environmental surcharge to recover the costs of approved environmental investments both past and future. Interestingly, Kentucky has also allowed cost recovery for pollution control projects outside of Kentucky; in two cases, it has allowed Kentucky Power to recover its share of the costs of pollution control projects at facilities belonging to other companies in the AEP pool.

Our analysis included cases involving CPCNs for pollution control add-ons, ECPs, or amendments to previously existing ECPs. The statute implementing the ECP process (KRS 278.183(2)) requires the Commission to complete its proceedings within six months of an ECP application. Because of this statute, ECP cases tend to be concluded in close to exactly six months. Applications for CPCNs are sometimes filed in the same case as an ECP and sometimes filed separately. When they are filed with an ECP, they are concluded in the statutorily required six months. When filed separately, there is slightly more variability, but they are generally concluded in six months or less.

Maryland. Maryland is a deregulated state, and therefore the PSC does not offer any ratemaking treatment for environmental costs. Maryland utilities are required, however, to file for a CPCN at least 180 days before modifying a power plant in a way that changes its emissions, which includes emissions controls. Our analysis included the modifications that were undertaken in compliance with Maryland's 2007 Healthy Air Act, which requires NO_X and SO_2 reductions at coal-fired power plants. This included eight cases of applications for CPCNs for add-on emissions controls. The average time from application to approval was eight months. It is important to note that because of the timeframe allowed for compliance with the Healthy Air Act, there was a period from late 2006 to mid-2007 during which multiple CPCN applications were being processed simultaneously; nonetheless, the process of approving these technologies never took longer than a year.

Minnesota. Minnesota utilities are allowed to recover specific environmental costs through an emissions reduction rider. Initially, utilities were only allowed to recover environmental costs outside of a general rate case if they were incurred voluntarily, i.e., they were not required to be incurred because of a law, settlement agreement, or other mandate. In 2006, with the passage of the Mercury Emissions Reduction Act, utilities were allowed to recover the costs incurred in carrying out required Mercury Emissions Reduction Plans, as well as for other emissions reduction activities undertaken along with the mercury reductions, even if those reductions were required for compliance with an existing mandate. Our analysis involved two cases dealing with voluntary emissions reduction programs, and five involving Mercury Emissions Reduction Compliance Plans and their associated cost recovery. Additionally, a 2010 law allows utilities to apply for an advance determination of prudence for an emissions control project; this provides more assurance for the utility that the costs of the project will be recoverable in rates. The first case under this new statute, filed by Otter Tail Power Company (Case 10-1082), has not yet been decided.

Missouri. No CPCN is required for pollution control projects in Missouri, and cost recovery is only allowed after a project is deemed "used and useful," i.e., after it is completed. However, there are some limited assurances that a company can get from the PUC before they construct a project through the filing of regulatory plans. In 2005, three utilities, Kansas City Power & Light (KCP&L), Aquila (now KCP&L Greater Missouri Operations), and Empire District Electric Company, filed "experimental regulatory plans" with the commission that each contained, among other provisions, plans to install environmental upgrades at coal-fired Iatan Unit 1, in which each utility has an ownership stake.

The assurances and approvals that each company sought were different. Both Empire and KCP&L sought and received assurance from the Commission that their environmental upgrades would not be excluded from rate base on the grounds that the projects were not "necessary or timely" or that they should have used alternative technologies. However, the agreements do not preclude the Commission from challenging the prudence of the environmental expenditures or proposing recovery of a different dollar amount in the next rate case. In contrast, while Aquila sought advance assurance in its first application for approval of its experimental regulatory plan that environmental upgrades at Iatan 1 were "necessary, timely, and prudent" to serve its customers, it eventually amended its application. Their amended application asked only for permission from the Commission to encumber its generating assets in the process of receiving a loan to finance the pollution control upgrades. Approval of the three cases took an average of 5 months, although it is worth noting that the informal workshop process that preceded the filing of KCP&L's regulatory plan lasted over 9 months.

New Jersey. New Jersey is a deregulated state, and the price of electric generation is set by the market rather than the PUC. No CPCN is required for the construction of pollution control retrofits.

New York. New York is a deregulated state, and the price of electric generation is set by the market rather than the PUC. No CPCN is required for the construction of pollution control retrofits.

North Carolina. In 2002, North Carolina passed the Clean Smokestacks Act, requiring reductions in NO_X and SO_2 emissions at power plants in the state owned by Duke and Progress Energy Carolinas. This bill authorized a specific amount of environmental compliance costs to be amortized for each utility, and required the utilities to submit compliance plans to the North Carolina Utilities Commission. However, review of the plans was largely left to the state's Department of Environmental and Natural Resources, and the Commission did not issue any orders formally approving the compliance plans. The Commission does not issue pre-approvals for emissions control projects. Thus, North Carolina was not included in the timing analysis.

Ohio. No project-specific construction approvals are required in Ohio, which is partially deregulated. Utilities can recover the costs of environmental investments in their rates through the provisions of an Electric Security Plan (ESP) or Market Rate Offer (MRO) – the methods by which Ohio utilities now set their rates – but this has traditionally been used to recover the cost of past investments rather than planned or projected ones. In AEP Ohio's most recent ESP proposal, however, the company has requested that its existing Environmental Investment Carrying Charge Rider be altered to recover projected costs; this has not yet been ruled on. [56] Thus, there are no data available yet for how long it takes for Ohio utilities to receive approval for environmental cost recovery prior to construction.

Pennsylvania. Pennsylvania is a deregulated state, and the price of electric generation is set by the market rather than the PUC. No CPCN is required for the construction of pollution control retrofits.

Virginia. The Virginia SCC does not require any siting approvals for pollution control projects. Utilities can recover the costs of pollution control projects in two ways: through a base rate case or through an environmental and reliability (E&R) rate surcharge. The Virginia SCC has ruled that utilities cannot recover projected future costs through the E&R surcharge, because the statute requires recoverable costs to have been "prudently incurred," in the past tense.[57] Projected future costs can be recovered in base rate cases to the extent that they can be "reasonably predicted to occur" during the rate year.[58] This "reasonably predicted" standard, however, is difficult to meet. The Commission has determined in both of Appalachian

[56] Ohio PUC Case 11-346-EL-SSO.
[57] *Application of Appalachian Power Company requesting Commission approval for adjustment of the Company's capped rates.* Case No. PUE-2005-00056, Commission Order. October 14, 2005.
[58] Virginia State Code § 56-235.2.

Company's rate cases that have included projected pollution control expenses that these expenses could not be "reasonably" predicted, and were not eligible for inclusion in base rates.[59] As a result, there is generally no process by which Virginia utilities can receive pre-approval for pollution control projects, and the state was not included in the timing analysis.

West Virginia. Section 24-2-4e of the West Virginia code allows utilities to use a special form of financing, called environmental control bonds, to pay for environmental control projects. These bonds are backed by assurance of cost recovery from ratepayers. An application for financing with these bonds must be filed with along with an application for a CPCN to engage in environmental control activities. Only two utilities so far (Monongahela Power and Potomac Electric – both d/b/a Allegheny Power) have taken advantage of this provision, and the case took slightly over a year to conclude. West Virginia also allows utilities to recover costs on pollution control construction, including CWIP, in the more traditional form of cost recovery riders. This process was used by Appalachian Power for its Mountaineer and John Amos scrubbers, and took slightly less than a year. A detailed discussion of these processes and the WV PSC is included as a case study in Section IV.

Wisconsin. In Wisconsin, utilities are required to receive a Certificate of Authority before beginning any construction at their facilities, including emissions control projects. In these proceedings, the PSC reviews the project, including its proposed costs, although no assurances of cost recovery are given nor are utilities allowed to recover any costs before they are incurred. The length of these cases tends to vary greatly, generally depending on whether there are intervenors and public hearings. Cases with no intervenors can take less than a month, while those with intervenors and hearings often last more than a year.

[59] *Application of Appalachian Power Company requesting Commission approval of an increase in electric rates.* Case No. PUE-2006-00065, Final Order (May 15, 2007); *Application of Appalachian Power Company for a statutory review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to section 56-585.1 A of the Code of Virginia*. Case No. PUE-2009-00030, Final Order (July 15, 2010).

APPENDIX D. DETAILS OF CASES USED IN TIMING ANALYSIS

Table I. Colorado

Owner / Power plant(s)	Relevant Case Numbers	Retrofits[60]	Approval sought	Dates	Time from application to approval (days)
PSCo / Arapahoe, Cherokee, Valmont	98A-511E	Sorbent injection at Arapahoe 3 and 4 and Cherokee 1 and 2; FGD at Cherokee 3 and 4 and Valmont 5.	Cost recovery (rider implemented in later case)	Applied 11/12/1998 Approved 6/16/1999	216
PSCo / Comanche	04A-214E 04A-215E 04A-216E	FGD, advanced low-NO_X technology, and sorbent injection at Comanche 1 and 2	Determination of prudence for cost recovery, including CWIP	Applied 4/30/2004 Approved 1/21/2005	266
PSCo / Pawnee, Hayden	10M-245E	SCR, FGD, and sorbent injection at Pawnee; SCR at Hayden 1 and 2.	Presumption of need for CPCN; accrual of AFUDC	Applied 8/13/2010 Approved 12/15/2010 (note: docket opened and proceedings began 5/7/2010)	124

Table II. Florida

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Gulf Power / Crist	930613	Precipitator upgrades, low-NO_X burners, and over-fire air at Crist 6 and 7, flue gas conditioning at Crist 7	Cost recovery	Applied 6/22/1993 Approved 1/12/1994	204
Florida Power & Light / Port Everglades, Riviera, Turkey Point	930661	Low-NO_X burners at Port Everglades 1-4, Riviera 3 and 4, and Turkey Point 1 and 2	Cost recovery	Applied 7/7/1993 Approved 10/29/1993	114
Gulf Power / Crist	980345	Low-NO_X burners at Crist 4 and 5	Cost recovery	Applied 2/12/1998 Approved 6/9/1998	117

[60] For all tables in this section, this column includes only add-on pollution control technologies for air emissions (NO_X, SO_2, PM, and HAPs). Other environmental compliance projects (e.g., repowering, ash ponds, cooling towers, fuel-switching, installation of monitors) were included in some of these filings but not listed in the table.

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Tampa Electric Company / Big Bend	980693	FGD at Big Bend 1 and 2	Cost recovery	Applied 5/15/1998 Finalized 4/19/1999 (note: original decision - 1/11/1999 - was appealed)	349
Gulf Power / Smith	990667	Sodium injection system at Smith	Cost recovery	Applied 5/24/1999 Approved 10/5/ 1999 Finalized 11/23/1999	183
Tampa Electric / Big Bend	000685	FGD optimization at Big Bend 1-3	Cost recovery	Applied 6/2/2000 Approved 10/18/2000 Finalized 11/13/2000	164
Gulf Power / Crist	020943	Relocation of precipitator at Crist 7; SCR at Crist 7	Cost recovery	Applied 8/30/2002 Approved 10/9/2002 Finalized 11/18/2002	80
Florida Power & Light / Manatee	020007	NO_X reburn technology at Manatee 1 and 2	Cost recovery	Applied 9/9/2002 Approved 12/10/2002	92
Tampa Electric Company / Big Bend	030226	Separated Overfire Air (SOFA) at Big Bend 4	Cost recovery	Applied 3/5/2003 Approved 6/6/2003 Finalized 7/2/2003	119
Florida Power & Light / Port Everglades	030007	ESP at Port Everglades 1-4	Cost recovery	Applied 9/8/2003 Approved 11/25/2003	78
Tampa Electric Company / Big Bend	040750	Pre-SCR retrofits at Big Bend 1-3, SCR at Big Bend 4	Cost recovery	Applied 7/15/2004 Approved 10/11/2004 Finalized 11/4/2004	112
Gulf Power Company / Smith	040007	ESP upgrades at Smith 2	Cost recovery	Applied 9/3/2004 Approved 12/1/2004	89
Tampa Electric Company / Big Bend	041376	SCRs on Big Bend 1-3, alkali injection on Big Bend 1-3	Cost recovery	Applied 12/7/2004 Approved 5/9/2005 Finalized 6/3/2005	178
Progress Energy Florida / Crystal River, Anclote	050316	FGD and SCR on Crystal River 1, 2, 3 and 5; low NO_X burners, overfire air, and SNCR on Anclote 1	Eligibility of Phase I CAMR/CAIR compliance costs for recovery in ECRC	Applied 5/6/2005 Approved 10/14/2005 Finalized 11/9/2005	187
Florida Power & Light	050007	Initial engineering work for CAIR compliance	Cost recovery	Applied 8/8/2005 Approved 12/22/2005	136
Tampa Electric Company / Big Bend	050958	FGD upgrades at Big Bend 1-4	Cost recovery	Applied 12/27/2005 Approved 6/11/2007 (note: original decision - 7/10/2006 - was appealed)	531

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Progress Energy Florida / Crystal River, Anclote	060007-EI	FGD and SCR at Crystal River 1 and 2, low NO_X burners and overfire air burners at Anclote 1 and 2	Approval of CAMR/CAIR compliance plan (subject to yearly update) and inclusion of 2005 and 2006 costs for cost recovery	Applied 3/31/2006 Approved 11/22/2006	236
Florida Power & Light / St. Johns River, Scherer, Cape Canaveral, Port Everglades, Putnam, Turkey Point	060007-EI	SCR at St. Johns River 1 and 2; FGD, SCR, baghouse and sorbent injection at Scherer 4; low-NO_X burners and reburn at Cape Canaveral 1 and 2, Port Everglades 3 and 4, and Turkey Point Fossil 1 and 2; water injection at Putnam 1 and 2	Approval of CAMR/CAIR compliance plan (subject to revision) and inclusion of 2007 costs for cost recovery	Applied 8/4/2006 Approved 11/22/2006	110
Gulf Power / Crist, Daniel, Smith, Scholz	060007-EI	FGD at Crist and Daniel; SCR at Crist 6; SNCR at Smith, Scholz and Daniel; low-NO_X burners at Daniel (preliminary construction)	Preliminary approval of CAMR/CAIR compliance plan and inclusion of 2007 costs for cost recovery	Applied 9/1/2006 Approved 11/22/2006	82
Gulf Power / Crist, Daniel, Smith, Scholz	070007-EI	FGD at Crist 4-7 and Daniel 1 and 2; SCR at Crist 6; SNCR at Smith1 and 2 and Daniel 1 and 2; low NO_X burners at Daniel 1 and 2	Full approval of CAMR/CAIR compliance plan and costs (subject to yearly updates)	Applied 3/30/2007 Approved 11/16/2007	231
Gulf Power / Crist	090007-EI	ESP upgrade at Crist 6	Cost recovery	Applied 8/28/2009 Approved 11/18/2009	82
Gulf Power / Daniel	100007-EI	SCRs at Daniel 1 and 2	Inclusion in Compliance Program and cost recovery	Applied 4/1/2010 Approved 11/15/2010	228

Table III. Georgia

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Georgia Power / Bowen, Branch, Hammond, Scherer, Wansley, Yates	25060	FGD at Bowen, Hammond, Scherer, Wansley and Yates; SCRs at Bowen, Scherer, and Yates; and baghouses at Scherer. Unit-level data not available.	Cost recovery rider	Applied 6/29/2007 Approved 12/31/2007	185
Georgia Power / Branch, Scherer	31958	FGD at Branch 3 and 4, Scherer 1-3; SCR at Branch 3, Scherer 1-3.	Cost recovery rider	Applied 7/1/2010 Approved 12/29/2010	181

Table IV. Indiana

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
PSI Energy / Gibson, Gallagher	41744	SCRs and boiler optimization at Gibson 1-3; SCRs at Gibson 4 and 5; SNCRs and boiler optimization at Gallagher 1-4	Approval of qualified pollution control technology (QPCP)	Applied 5/17/2000 Approved 2/14/2001	273
Vectren / Culley, Warrick, Brown	41864	SCRs at F.B. Culley 3, Warrick 4, and A.B. Brown 2	CPCN for clean coal technology (CCT), QPCP, rate rider	Applied 11/13/2000 Approved 8/29/2001	289
PSI Energy / Gallagher, Wabash, Cayuga, others	41744-S1	Low-NO_X burners at Gallagher 1-4; SNCR at Wabash 2-6; SCR at Cayuga 1; boiler optimization for almost all of company's coal-fired units	QPCP	Applied 8/14/2001 Approved 7/3/2002	323
	42061		CPCN for CCT, CWIP, and accounting treatment		
NIPSCO / Michigan City, Bailly, Schahfer	42150	SCR at Michigan City 12, Bailly 7 and 8 and Schahfer 14; low NO_X burners and over fired air at Schahfer 17 and 18.	QPCP, CPCN for clean coal technology, cost recovery	Applied 1/4/2002 Approved 11/26/2002	326

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Indianapolis Power & Light / Petersburg, Harding Street, Eagle Valley	42170	SCR at Petersburg 2 and 3 and Harding Street 7; SCNR at Harding Street 5 and 6 and Eagle Valley 6; ROFA®/ROTAMIX® at Eagle Valley 4 and 5; and Neural Network at Petersburg 1, Harding Street 5 and 6, and Eagle Valley 6.	QPCP, CPCN for CCT, cost recovery	Applied 2/1/2002 Approved 11/14/2002	286
Wabash Valley Power Cooperative	42174	SCR on Gibson Unit 5 (note: Wabash Valley co-owns with PSI; most determinations were made in cases 41744-S1 and 42061, above)	Permission to execute notes as evidence of indebtedness (for financing pollution control projects)	Applied 2/12/2002, 2/26/2002 Cases consolidated 3/26/2002 Approved 8/7/2002	196
	42189		QPCP, CPCN, cost recovery, accounting treatment		
PSI Energy / Gibson, Cayuga and Gallagher	42622	FGD at Gibson 1-3 and Cayuga 1 and 2, FGD upgrades at Gibson 4 and 5, combined ACI-baghouse at Gallagher 1-4	QPCP, CPCN for CCT, approval of compliance plan, cost recovery, accounting treatment	Applied 4/23/2004 Approved 5/24/2006	761
Vectren / Warrick, Culley	42861	FGD at Warrick 1, fabric filter at Culley 3	QPCP, CPCN for CCT, cost recovery	Applied 5/16/2005 Approved 2/22/2006	282
NIPSCO / R.M. Schahfer	43188	Advanced low-NO_X burners and overfire air at Schahfer 15, FGD upgrades at Schahfer 17 and 18	QPCP, CPCN for CCT, cost recovery, accounting treatment	Applied 12/8/2006 Approved 7/3/2007	207
Indiana Michigan Power / Tanners Creek, Rockport	43636	SNCR at Tanners Creek 1-3, ACI at Rockport 1 and 2	QPCP, CPCN for CCT, cost recovery through rate adjustment mechanism	Applied 1/30/2009 Approved 6/30/2009	151
Duke Energy Indiana / Gallagher	43873	Dry Sorbent Injection at Gallagher 2 and 4	CPCN and ongoing cost review (no cost recovery in this filing)	Applied 3/23/2010 Approved 9/8/2010	169

Table V. Kentucky

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Kentucky Utilities / Ghent, others	1993-00465	FGD at Ghent 1, NO_x burner enhancements at all Phase I units	Approval of environmental compliance plan (ECP) and environmental cost recovery (ECR)	Applied 1/20/1994 Approved 7/19/1994	180
Big Rivers Electric Cooperative / Green and Wilson; Henderson Municipal EPLS / Station 2	1994-00032	FGD at Henderson Municipal ELPS Station 2; FGD improvements at Green and Wilson; low-NO_X burners at all Phase I units	Approval of ECP and ECR	Applied 2/28/1994 Approved 8/31/1994	184
Louisville Gas & Electric / Mill Creek, Cane Run	1994-00332	Improving SO_2 removal systems at Mill Creek 1-4; ESP at Cane Run 4; low NO_X burners at Mill Creek and Cane Run	Approval of ECP and ECR	Applied 10/7/1994 Approved 4/6/1995	181
Kentucky Power / Big Sandy; Ohio Power / Gavin	1996-00489	Low-NO_X burners at Big Sandy Units 1 and 2; FGD at Gavin	Approval of ECP and ECR	Applied 11/27/1996 Approved 5/27/1997 [note: low-NO_X burners at Big Sandy were initially excluded from cost recovery, and this decision was ultimately litigated and reversed; case began 7/25/1998 and ended with settlement agreement 6/14/1999]	181
KU and LG&E/ Trimble, Mill Creek, Ghent, Brown	2000-00112	SCRs at Trimble County 1; Mill Creek 3 and 4; Ghent 1, 3 and 4; and Brown 3	CPCN	Applied 3/3/2000 Approved 6/22/2000	111
EKPC / Spurlock and Cooper	2000-00340	SCRs at Spurlock 1 and 2, Cooper 2	CPCN	Applied 06/30/2000 Approved 11/16/2000	139

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
KU / Ghent, Brown, Green River, Pineville, Tyrone	2000-00439	Low-NO_X burners at Ghent 2 and 4; SCR at Ghent 1, 3 and 4 and Brown 3; neural network technology, overfire air systems and burner modifications at Brown 1 and 2, Ghent 1 and 2, Green River 3, Pineville 3, and Tyrone 3.	Approval of amendment to ECP and ECR	Applied 10/20/2000 Approved 4/18/2001	180
LG&E / Trimble County, Mill Creek, Cane Run	2000-00386	SCRs at Trimble County 1 and Mill Creek 3 and 4; neural network technology, overfire air systems and burner modifications at Cane Run 4-6 and Mill Creek 1-4.	Approval of amendment to ECP and ECR	Applied 10/20/2000 Approved 4/18/2001	180
Kentucky Power / Big Sandy	2001-00093	SCR at Big Sandy 2	CPCN	Applied 4/6/2001 Approved 7/31/2001	116
LG&E / Mill Creek, Cane Run, Trimble County	2002-00147	FGD improvements at Mill Creek 1-4; ESP upgrades at Mill Creek 2 and 3, Cane Run 1-3, and Trimble County 1	Approval of amendment to ECP and ECR	Applied 8/12/2002 Approved 2/11/2003	183
Kentucky Power / Big Sandy	2002-00169	Over-fire air with water injection and boiler tube overlays at Big Sandy 1; SCR and ESP improvements at Big Sandy 2.	Approval of amendment to ECP and ECR	Applied 9/30/2002 Approved 3/31/2003	182
EKPC / Spurlock, JK Smith	2004-00321	SNCR, baghouse, and flash dry absorber at Spurlock's Gilbert Unit; ESP at Spurlock 1; low-NO_X burners at JK Smith 1-7; SCRs at Spurlock 1 and 2	Approval of ECP and ECR	Applied 9/17/2004 Approved 3/17/2005	181
KU / Ghent, Brown	2004-00426	FGD at Ghent 2-4 and Brown 1-3	CPCN, approval of amendment to ECP and ECR	Applied 12/20/2004 Approved 6/20/2005	182

Owner / Power plant(s)	**Relevant Case Numbers**	**Retrofits**	**Approval sought**	**Dates**	**Time from application to approval (days)**
LG&E / Trimble County, Cane Run	2004-00421	FGD refurbishment and improvements at Trimble County 1 and Cane Run 5 and 6.	Approval of amendment to ECP and ECR	Applied 12/20/2004 Approved 6/20/2005	182
(Kentucky Power) Ohio Power / Amos, Cardinal, Gavin, Kammer, Mitchell, Muskingum River, Phillip Sporn; I&M / Rockport, Tanners Creek	2005-00068	53 projects located at Ohio Power and I&M generating stations	Approval of amendment to ECP and cost recovery for upgrades at other facilities in AEP pool	Applied 3/8/2005 Approved 9/7/2005	183
EKPC / Spurlock	2005-00417	FGD at Spurlock 2	CPCN	Applied 10/7/2005 Approved 4/18/2006	193
EKPC / Spurlock	2006-00132	FGD at Spurlock 1	CPCN	Applied 3/27/2006 Approved 8/11/2006	137
KU / Ghent, Trimble, Brown	2006-00206	SCR at Ghent 2; KU's share of SCR, ESP and FGD at Trimble 2; sorbent injection at Ghent 1, 3, and 4,; ESP upgrades at Brown	CPCN, approval of amendment to ECP and surcharge	Applied 6/23/2006 Approved 12/21/2006	181
LG&E / Trimble, Mill Creek	2006-00208	SCR, ESP and FGD at Trimble 2; sorbent injection at Mill Creek 3 and 4 and Trimble 1	Amended compliance plan and ECR	Applied 6/23/2006 Approved 12/21/2006	181
(Kentucky Power) Ohio Power / Amos, Cardinal, Gavin, Mitchell, Sporn; Indiana Michigan Power / Rockport, Tanners Creek	2006-00307	44 projects located at Ohio Power and I&M generating stations	Approval of environmental compliance plan amendment and cost recovery for upgrades at other facilities in AEP pool	Applied 7/28/2006 Approved 1/24/2007	180
EKPC / Dale, Spurlock, Cooper	2008-00115	Low-NO_X burners at Dale 1-4 and Spurlock 1; FGD at Spurlock 1 and 2; pollution control facilities at Spurlock 4	Approval of ECP amendment and ECR	Applied 3/28/2008 Approved 9/29/2008	185
EKPC / Cooper	2008-00472	FGD at Cooper 2	CPCN	Applied 11/14/2008 Approved 5/1/2009	168

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
KU / E.W. Brown	2009-00197	SCR at Brown 3	CPCN, approval of environmental compliance plan amendment and surcharge	Applied: 6/26/2009 Approved: 12/23/2009	180
EKPC / Cooper, Spurlock	2010-00083	FGD, SCR and fabric filter at Cooper 2	Approval of ECP amendment and ECR	Applied 3/29/2010 Approved 9/24/2010	179

Table VI. Maryland

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Constellation / Brandon Shores	9075	FGD, sorbent injection, and fabric filter at Brandon Shores 1 and 2	CPCN	Applied 8/23/2006 Approved 6/4/2007	285
Mirant / Chalk Point	9079	SCR at Chalk Point 1	CPCN	Applied 10/10/2006 Approved 2/15/2007	128
Constellation / Wagner	9083	SNCR at Wagner 2, sorbent injection at Wagner 2 and 3	CPCN	Applied 11/1/2006 Approved 5/8/2007	188
Constellation / Crane	9084	SNCR and sorbent injection at Crane 1 and 2	CPCN	Applied 11/2/2006 Approved 7/31/2007	271
Mirant / Morgantown	9085	FGD at Morgantown 1 and 2	CPCN	Applied 11/2/2006 Approved 10/22/2007	354
Mirant / Chalk Point	9086	FGD at Chalk Point 1 and 2	CPCN	Applied 11/3/2006 Approved 8/6/2007	276
Mirant / Dickerson	9087	FGD at Dickerson 1-3	CPCN	Applied 11/3/2006 Approved 7/19/2007	258
Mirant / Dickerson	9140	SNCR at Dickerson 1-3	CPCN	Applied 4/24/2008 Approved 10/27/2008	186

Table VII. Minnesota

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Northern States Power / King, High Bridge, Riverside	02-633	SCR, FGD and fabric filter at King; repowering to natural gas of High Bridge and Riverside, including NO_X controls	Approval of emissions reduction plan and cost recovery rider	Applied 7/26/2002 Approved 3/8/2004	591
Minnesota Power / Taconite Harbor, Laskin	05-1678	Low-NO_X burners and overfire air at Laskin 1 and 2; ROFA, SNCR, and sorbent injection (Mobotec system) at Taconite Harbor	Approval of emissions reduction plan and cost recovery rider	Applied 10/14/2005 Approved 6/13/2006	242
Northern States Power / Sherco	06-1315	Preliminary work to develop mercury compliance plan; activated carbon injection on Sherco 3.	Deferred accounting treatment of costs, carrying costs on CWIP	Applied 9/15/2006 Approved 1/31/2007	138
Minnesota Power / Boswell	06-1501	ACI, low-NO_X burners, overfire air, SCR, FGD, and fabric filter at Boswell 3.	Approval of mercury emissions reduction plan and cost recovery rider, return on CWIP	Applied[61] 10/30/2006 Approved 10/26/2007	361
Northern States Power / Sherco and King	07-1601 07-1602	ACI at Sherco 3 and King.	Approval of mercury emissions reduction plan (no cost recovery approval)	Applied 12/21/2007 Approved 11/6/2008	321
Northern States Power / Sherco and King	09-847	ACI at Sherco 3 and King.	Cost recovery rider, return on CWIP	Applied 7/16/2009 Approved 11/4/2009	111
Northern States Power / Sherco	09-1456	ACI at Sherco 1 and 2.	Approval of mercury emissions reduction compliance plan	Applied 12/21/2009 Approved 11/4/2010	318

[61] Plan submitted 10/30/2006; petition for approval filed 1/26/2007. If counting from the latter date, the process took 273 days.

Table VIII. Missouri

Owner / Power plant(s)	Relevant case numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Empire / Iatan 1 and Asbury	EO-2005-0263	FGD, SCR, and baghouse at Iatan 1; SCR at Asbury	Assurance that environmental upgrade investments will not be excluded from rate base on the ground that they were not necessary or timely or that Empire should have used alternative technologies.	Applied 2/4/2005 Approved 8/2/2005	179
Aquila / Iatan 1	EO-2005-0293	FGD, SCR, and baghouse at Iatan 1	Permission to encumber Missouri electric assets for the purposes of financing pollution control upgrades	Applied 3/2/2005 Approved 8/9/2005	160
KCP&L / Iatan 1 and La Cygne	EO-2005-0329	FGD, SCR, and baghouse at Iatan 1 and La Cygne 1	Assurance that environmental upgrade investments will not be excluded from rate base on the ground that they were not necessary or timely or that KCP&L should have used alternative technologies.	Stipulation and agreement filed 3/28/2005 Approved 7/28/2005 (Note: informal workshop process leading up to stipulation and agreement began 5/6/2004 and ended 2/18/2005)	122

Table IX. West Virginia

Owner / Power plant(s)	Relevant case numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
Allegheny / Fort Martin	05-0402-E-CN 05-0750-E-PC	FGD at Fort Martin	CPCN, financing through environmental control bonds	CPCN application 3/24/2005 Financing application 5/24/2005 Approved 4/7/2006	379
Appalachian Power Company / Mountaineer, Amos	05-1278-E-PC-PW-42T	FGD at Mountaineer and Amos 1-3	Cost recovery, including CWIP	Applied 8/26/2005 Approved 7/26/2006	334

Table X. Wisconsin

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
WPL, WPSC, and MG&E / Columbia	05-CE-109	SCR at Columbia 2	Certificate of authority	Applied 4/15/1999 Approved 9/22/1999	160
WEPCO / Oak Creek	6630-CE-274	Low-NO_X burners and overfire air at Oak Creek 7 and 8	Certificate of authority	Applied 4/12/2000 Approved 5/31/2000	49
WPL and WPSC / Edgewater	05-CE-114	Overfire air and combustion improvements at Edgewater 4	Certificate of authority	Applied 8/15/2000 Approved 9/27/2000	43
WPL / Edgewater	6680-CE-162	Combustion enhancements and overfire air at Edgewater 3	Certificate of authority	Applied 4/30/2001 Approved 6/15/2001	46
WPL / Edgewater	05-CE-118	Low-NO_X burners and combustion improvements at Edgewater 5	Certificate of authority	Applied 5/2/2001 Approved 6/15/2001	44
WPL, WPSC, and Madison Gas and Electric / Columbia	05-CE-119	Combustion improvements and separated overfire air at Columbia 2	Certificate of authority	Applied 6/4/2001 Approved 7/3/2001	29
NSPW / French Island	4220-CE-163	FGD and fabric filter at French Island 1 and 2	Certificate of authority	Applied 7/30/2001 Approved 8/14/2001	15
WPL, WPSC, and Madison Gas and Electric / Columbia	05-CE-129	Combustion enhancements and separated overfire air at Columbia 1	Certificate of authority	Applied 11/14/2001 Approved 1/31/2002	78
WPL / Nelson Dewey	6680-CE-163	Neural network, overfire air and combustion enhancements at Dewey 2	Certificate of authority	Applied 12/11/2001 Addendum 4/18/2002 Approved 5/28/2002	168
WEPCO / Presque Isle	6630-CE-287	TOXECON mercury control at Presque Isle 7-9	Certificate of authority	Applied 8/29/2003 Approved 3/12/2004	196
WEPCO / Presque Isle	6630-CE-290	Baghouse at Presque Isle 5 and 6	Certificate of authority	Applied 5/26/2004 Approved 7/30/2004	65
WPL / Nelson Dewey	6680-CE-169	Combustion enhancements, overfire air and neural network at Dewey 1	Certificate of authority	Applied 9/10/2004 Approved 10/20/2004	40

Owner / Power plant(s)	Relevant Case Numbers	Retrofits	Approval sought	Dates	Time from application to approval (days)
WPSC / Weston	6690-CE-190	Overfire air and combustion modifications at Weston 3	Certificate of authority	Applied 5/27/2005 Approved 8/31/2005	96
WEPCO / Valley Power Plant	6630-CE-297	Low-NO_X burners and overfire air at Valley 1 and 2	Certificate of authority	Applied 5/3/2007 Approved 7/23/2007	81
WEPCO / Oak Creek Power Plant	6630-CE-299	FGD and SCR on Oak Creek 5-8.	Certificate of authority	Applied 6/21/2007 Approved 7/10/2008	385
WPSC / Weston	6690-CE-195	Separated overfire air and low NO_X burners at Weston 1 and 2	Certificate of authority	Applied 10/19/2007 Approved 12/13/2007	55
WPSC / Pulliam	6690-CE-196	Separated overfire air and low NO_X burners at Pulliam 5-8	Certificate of authority	Applied 10/19/2007 Approved 12/13/2007	55
NSPW / Bay Front	4220-CE-167	Separated overfire air and combustion enhancements at Bay Front 1 and 2	Certificate of authority	Applied 2/15/2008 Approved 3/13/2008	27
WEPCO and WPL / Edgewater	05-CE-137	SCR on Edgewater 5	Certificate of authority	Applied 11/14/2008 Approved 5/27/2010	559

APPENDIX E. INTERVENORS IN COLORADO CASE STUDY

Intervenor Name	Rationale for Intervenor Status (June 2010)
American Coalition for Clean Coal Electricity (ACCCE)	ACCCE advocates for new advanced coal technologies. Members include coal producers in Colorado and railroad companies that transport coal. These companies feel they will be impacted twice by switching to natural gas, both through loss of revenues and higher operating costs.
Anadarko Energy Services	Buys and sells natural gas. Is an affiliate of Anadarko Petroleum Company which produces natural gas for Anadarko Energy Services. Anadarko is listed as winning a long-term gas contract with PSCo, which is part of the filing PSCo submitted for PUC approval.
Associated Governments of CO	Mesa, Garfield, Rio Blanco, Moffat, and Routt Counties contain 63 percent of the 2,392 coal mining jobs in the State. Average pay is $102,077, thus representing a significant portion of tax revenues.
Citizens	
City of Boulder, CO	PSCo's Valmont Station is located within the city limits, and the City is concerned about air quality and GHG contributions.
City of Denver	Ozone nonattainment area; believes that Denver citizens are adversely impacted by pollution from Cherokee Station in residential areas.
Climax Molybdenum Company with CF&I Steel and Evraz Rocky Mountain Steel	These companies are large power consumers. Climax is the second largest retail electric consumer in the PSCo service area. They are concerned about rate increases and potential reliability disruptions.
CO Department of Health	Advocates on behalf of public health for the citizens of Colorado.
CO Governors Energy Office	Concerned that the Emission Reduction Plan did not follow the spirit of the CACJ Act.
CO Interstate Gas Co. (CIG)	Owns and operates interstate transmission system for natural gas pipeline. Also transports gas from production areas to consumption zones.
CO Solar Energy Industries	Nonprofit group representing solar energy industries.
Colorado Department of Public Health and Environment (CDPHE)	Main reviewer of whether the PSCo emission reduction plan satisfies the requirements of the CACJ and reasonably foreseeable requirements. CACJ also specifies consultations between CDPHE and PSCo.
Colorado Energy Consumers	Group of energy consumers concerned about rate increases.
Colorado Independent Energy Association (CIEA)	
Colorado Mining Association (CMA)	CMA is a trade association representing over 900 members including coal producers who sell coal to PSCo for Cherokee, Hayden, and Valmont stations. Over 2.5 million tons of coal was sold to PSCo's affected plants in 2009.
Colorado Office of Consumer Counsel (COO)	Advocates on behalf of electricity ratepayers.

Intervenor Name	Rationale for Intervenor Status (June 2010)
Colorado Oil & Gas Association	Trade association looking to expand gas in the Rocky Mountains. States that natural gas is one of company's leading creators of jobs and tax revenues, with over 137,000 jobs in Colorado.
Colorado Springs Utilities, Tri-State Generation, Transmission	Purchasers of wholesale power, they are concerned about future rate increases. No mention of existing contracts. They specifically mention Craig and Nuca stations, which are not affected by PSCo's compliance plan.
Federal Executive Agencies (FEA)	Advocates on behalf of Federal Agencies (not as a representative of the U.S. Government). The FEA here represents the Buckley Air Force Base in Aurora, CO. FEA is concerned about potential rate increases as it is a large power consumer.
Holy Cross Electric Association	Public utility, deregulated from Commission rate jurisdiction. Purchases a substantial portion of wholesale power from PSCo, via long-term contracts which are in place and could be impacted by rate increases as a result of the compliance plan.
Intermountain Rural Electric (IREA)	Electric association of utilities (deregulated from rates). IREA purchases power from PSCo.
Interwest Energy Alliance	Trade association for renewable energy sources; supports the use of wind and solar generation to replace coal.
Noble Energy, Chesapeake, and Encana "Gas intervenors"	Noble owns gas plays and sells natural gas. Chesapeake is one of the largest producers of natural gas, and Encana delivers gas production and has gas plays in Colorado. The Gas intervenors would like to see more gas used in Colorado.
Peabody Energy Corporation	Corporation whose main businesses include the mining and selling of coal. Estimated assets of 196 million tons of coal are mined in Colorado. Peabody operates Twentymile mine, near Oak Creek, Colorado. Peabody sold 7.8 million tons of coal mined from the Twentymile Mine to PSCo in 2009, going to Cherokee, Valmont, and Arapahoe plants. They have over 500 personnel. The coal is low-sulfur. Long-term contracts are in place with PSCo that could be disturbed by premature retirements of coal-fired boilers.
School District #1	School District, concerned about children's health and clean air.
Southwest Generation	An IPP that owns gas generation in the area (450 MW) and has power purchase agreements with PSCo through 2012.
Thermo Power & Electric LLS	Sells power to PSCo from Greenly, a 72 MW natural gas plant. Advocates to be part of the solution in the compliance plan.
Walmart and Sam's West	Owns 45 facilities in the PSCo service area, and is a large commercial retail customer of PSCo, using about 150 million kWh/yr. Increased electricity rates would "dramatically impact Walmart operating costs."
Weld County, CO	County Commissioners of Weld County. The county holds deposits of natural gas and is in support of using more gas to fuel the state.
Western Fuels & Colorado Rural Electric Association (CREA)	Western Fuels/CREA purchases wholesale power from PSCo and operates New Horizon coalmine, which delivers coal to PSCo.
Western Resource Advocates	NGO supporting gains in environmental protection.

Appendix F. Relevant Articles

Greenwire. *E-Mails Showing Possible Illicit Talks Are the Latest in Duke Scandal*. E&E Publishing, LLC. March 9, 2011. http://www.eenews.net/Greenwire/2011/03/09/19/.

Greenwire. *Top Duke Executive Resigns over E-mail Scandal*. E&E Publishing, LLC. December 7, 2010. http://www.eenews.net/Greenwire/2010/12/07/8/.

John Blair. *Daniels Acts To Save Face In Utility Regulation Scandal*. Valley Watch. October 6 2010. http://valleywatch.net/?p=1027.

Glossary

AAC – Automatic Adjustment Clause

ACCCE – American Coalition for Clean Coal Electricity

ACI – Activated carbon injection

AEP – American Electric Power Company

AFUDC – Allowance for Funds Used During Construction

APCo – Appalachian Power Company

CAC – Citizen's Action coalition

CACJ – Colorado Clean Air-Clean Jobs Act

CAD – Consumer Advocacy Division

CAIR – Clean Air Interstate Rule

CAMR – Clean Air Mercury Rule

CDPHE – Colorado Department of Public Health and Environment

CEM – Continuous Emissions Monitor

CIEA - Colorado Independent Energy Association

CMA – Colorado Mining Association

CO_2 – Carbon dioxide

CPCN – Certificate of Public Convenience and Necessity

CPSG – Constellation Power Source Generation, Inc.

CRS – Colorado Revised Statutes

CWIP – Construction Work in Progress

ECB – Environmental Control Bond

ECCR – Environmental Compliance Cost Rider

ECP – Environmental Compliance Plan

ECR – Environmental Cost Recovery

ECRC – Environmental Cost Recovery Clause

EEI – Edison Electric Institute

EPA – Environmental Protection Agency

EPAct – Energy Policy Act

ERA – Emissions Reduction Adjustment

ESP – Electrostatic Precipitator

FCC – Federal Communications Commission

FEA – Federal Executive Agencies

FERC – Federal Energy Regulatory commission

FGD – Flue Gas Desulfurization

FP&L – Florida Power & Light

FRCC – Florida Reliability Coordinating Council

GAO – Government Accounting Offices

GBRA – Generation Base Rate Adjustment

GIG – Georgia Industrial Group

GTMA – Georgia Traditional Manufacturers Association

HAA – Healthy Air Act

IRP – Integrated Resource Plan

IPPs – Independent Power Producers

ISO – Independent System Operator

IURC – Indiana Utility Regulatory Commission

KCP&L – Kansas City Power & Light

kWh – Kilowatt-hour

kW – Kilowatt

MACT – Maximum Achievable Control Technology

MDE – Maryland Department of the Environment

MDPSC – Maryland Public Service Commission

MISO – Midwest Independent System Operator

MJB&A – M.J. Bradley & Associates

MW – Megawatt

NAAQS – National Ambient Air Quality Standards (NAAQS)

NARUC – National Association of Regulatory Utility Commissioners

NASUCA – National Association of State Utility consumer Advocates

NERC – North American Reliability Corporation

NESHAP – National Emission Standards for Hazardous Air Pollutants

NO_X– Nitrogen oxides

NSPS – New Source Performance Standards

NSR – New Source Review

O&M – Operations and Maintenance

OCC – Office of Consumer Counsel

OUCC – Office of Utility consumer Counselor

PAC – Powder Activated Carbon

PJM – PJM Interconnection, LLC

PPRP – Power Plant Research Program

PSCo – Public Service Company of Colorado

PSC – Public Service Commission

PSD – Prevention of Significant Deterioration

PSI – PSI Energy, Inc.

PUC – Public Utility Commission

PURPA – Public Utility Regulatory Policies Act

QPCP – Qualified Pollution Control Property

RGGI – Regional Greenhouse Gas Initiative

ROFA – Rotating Overfire Air

RPS – Renewable Portfolio Standard

RRR – Application for Rehearing, Reargument, or Reconsideration

RTO – Regional Transmission Organization

SCC – State Corporation Commission

SCR – Selective Catalytic Reduction

SERC – Southeastern Electric Reliability Council

SNCR – Selective Non-Catalytic Reduction

SO_2 – Sulfur dioxide

VOCs – Volatile Organic Carbons

WECC – Western Electricity coordinating Council

WRA – Western Resource Advocates