Chapter 8. Retire Aging Power Plants

1. Profile

Retiring aging fossil-fired electric generating units (EGUs) can produce significant reductions in greenhouse gas (GHG) emissions. This is particularly true when the EGUs in question are existing coal-fired units, because their carbon dioxide (CO_2) emissions are typically double those of natural gas combined-cycle EGUs. Most of the EGUs currently slated for retirement are coal-fired units, resulting from greater fuel price competition with natural gas, higher operating costs, and new environmental regulations such as the US Environmental Protection Agency's (EPA) recent Mercury and Air Toxics Standards (MATS). The EPA has identified 233 coal-fired, non-cogeneration EGUs which, based on recent announcements, have retired or are expected to do so before 2016.[1]

Although retiring aging coal-fired EGUs is becoming more and more prevalent, these decisions remain a sensitive topic. Despite the likely environmental benefits, retiring an aging EGU has the potential to produce profound economic consequences for utility ratepayers, companies, and the community where the unit is located. Paying for a unit to retire can be expensive and disruptive. However, when weighed against various policy alternatives, retiring an aging EGU may be a lower-cost solution to the challenge of emissions reductions and worthy of inclusion in a state's Clean Air Act compliance plans.

There are numerous factors that can affect a plant owner's or regulator's decision to continue operating an aging EGU or to retire it. These include forward-looking market factors and environmental regulatory requirements. The ability to recover past plant-related investments will also heavily influence the decision. States that consider EGU retirement as a compliance option will have to consider these issues, and the varying degrees to which these factors support such a decision. Consideration of these same issues has led many plant owners and regulators to require aging EGUs to be repowered (to utilize a lower-emitting fuel) instead of retired – a policy option reviewed in detail in Chapter 9. Along these lines, some observers have recommended (but not yet implemented) the idea that retirement deliberations be institutionalized through the adoption of a "birthday provision" whereby EGUs would automatically become subject to new source emissions standards upon expiration of their originally defined useful lifetime.

Although the EPA's Clean Power Plan proposal of June 2014 nowhere mandates EGU retirements, given the flexibility that the proposal would provide states, this option — with its related benefits and challenges — constitutes a potential compliance pathway worthy of state consideration.

2. Regulatory Backdrop

Most EGU retirement decisions begin with a decision by the owner of the EGU that it makes sense to retire the unit. There are also limited examples of decisions that are initiated by other decision-makers and imposed on EGU owners.

The market and regulatory context in which an EGU operates provides an additional backdrop and regulatory context for retirement decisions. In most cases, the owner of the EGU will need additional approvals before it can actually retire the unit. To understand these approvals it is helpful to review some of the terminology used to describe

1 The EPA reports that its "research found 233 coal-fired, non-cogeneration EGUs that have announced they will retire before 2016." US EPA. (2014, June). *State Plan Considerations – Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. p. 235, note 29 citing to Integrated Planning Model documentation includes a list of the announced retirements. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf. See Table 4-36 of Integrated Planning Model Documentation: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_4.pdf

EGU ownership and energy markets.

EGUs can be owned by "vertically integrated" utilities that own electric generation assets and an electric distribution system, and sell energy to retail customers within their retail monopoly jurisdiction. Large EGUs may be jointly owned by more than one party. Vertically integrated utilities can be investor-owned, publicly owned, or member-owned cooperatives. States vary in terms of whether and how each type of utility is regulated by the state public utility commission (PUC), with the common thread being that investor-owned utilities are regulated by PUCs everywhere. EGUs can also be owned by non-utility "independent power producers," also known as "merchant generators."

In some parts of the country, the electric power sector has been "restructured." Utilities in those areas were required to divest their ownership of EGUs. Although distribution utilities continue to exist in those areas, they only have a monopoly with respect to the distribution system. All EGUs in those areas are owned by merchants and the wholesale sale of electricity is a competitive market.

Today there are a variety of energy market structures in place around the United States. "Traditionally regulated" markets persist in many jurisdictions (principally in the West and the South). In those areas, most EGUs are owned and controlled by vertically integrated utilities, but some merchant generators own EGUs and sell energy to utilities through bilateral contracts. EGU dispatch decisions are made in those areas by the utility based on the needs of its customers. In other areas, competitive wholesale electricity markets have been created, in most cases spanning across state lines. Within those competitive wholesale markets, EGUs may be owned by vertically integrated utilities or by merchant generators, but decisions about which EGUs operate (and at what level of output) are made by an independent system operator (ISO) or regional transmission organization (RTO) based on system-wide customer needs and competitive bids made by EGU owners.

Returning to the issue of EGU retirements, in different jurisdictions retirements occur as a result of unit owner decisions, decisions from ISOs with organized wholesale markets that permit units to be "de-listed," and rulings from state regulatory commissions in "abandonment" proposals, planning dockets, or special accounting or rate-treatment processes.

Unit Owner Decisions

EGU owners make decisions to retire plants for various economic and other reasons explained in greater detail later in this chapter. In restructured jurisdictions, EGUs are owned by merchants, and retirement and cost considerations are not likely to be subject to PUC review. However, in jurisdictions with organized wholesale markets, those EGU owners' retirement decisions must be reviewed by the ISO or RTO as explained below. In traditionally regulated jurisdictions, EGU owners' retirement decisions must be reviewed and approved by state regulatory commissions except in cases in which the PUC has no regulatory authority (as is sometimes the case for publicly owned utilities and cooperatives and normally the case for merchant generators). These processes are described in more detail below.

ISO/RTO Decisions

In organized wholesale markets like the PJM Interconnection (PJM) or Midcontinent Independent System Operator RTOs, electric generation is made available through resource auctions and the establishment of a dispatch order for EGUs based on economic merit (see Chapter 21 for a more comprehensive discussion of dispatch order). For example, in the New England ISO's energy markets,[2] in order to participate an EGU owner needs to submit a bid reflecting the amount of energy that the generator can provide and the price, and that bid must clear through the auction. If the bid is successful (i.e., the unit owner has a position and a price), that EGU must deliver generation for the specific time and

2 Power plants that participate in organized markets are paid for both the energy they produce and for the generation capacity that they agree to provide. Electric energy is produced and sold daily at wholesale and then resold to end-use consumers. Capacity is typically sold over longer time periods in an attempt to ensure that generation resources will be available in the future and that there is enough time to build them. In PJM, for example, there is an annual auction for power delivery three years in the future. There are also other smaller capacity markets where, within that three-year time frame, power can be sold to ensure that precisely the right amount will be available when it is needed. For further discussion of capacity markets, see Chapter 19. For a more complete discussion of this topic, also see, e.g.: James, A. (2013, June 17). *Explainer: How Capacity Markets Work.* MidWest Energy News. Available at: http://www.midwestenergynews.com/2013/06/17/explainer-how-capacity-markets-work/

in the amount of capacity it bid. If it fails to do so, it could face a penalty, and would certainly forego any revenue for the electricity it failed to deliver. Additional details regarding capacity markets and dispatch are also provided in Chapters 19 and 21.

In this context, retirement involves removing an EGU from current or future auctions, a process called "de-listing." In the New England ISO's forward capacity market, existing resources are able to leave the market by submitting a "de-list" bid.[3] All de-list bids are subject to a reliability review by the ISO. If the ISO concludes that the unit submitting the de-list bid is needed for reliability purposes, the bid is rejected and the resource is retained.[4] Other RTOs and ISOs possess similar ability to deny EGU retirements that would jeopardize system reliability.[5]

Decisions in Traditionally Regulated Markets

Retirement of EGUs works differently in traditionally regulated or vertically integrated markets; there, EGU owners are relatively free to retire a unit if they wish. Owners make such decisions subject to reliability demands and to any additional constraints that might be included in a generator's permission to operate, that is, a "certificate of public convenience and necessity" or "certificate of public good" granted by a state commission where the generator is located.

For example, Public Service Company of Colorado, as part of its decision-making under Colorado's "Clean Air – Clean Jobs Act,"[6] relied on its own dispatch models and reviewed options across its system to "take action" (i.e., to retire, control, or fuel-switch a unit to natural gas). Companies in traditionally regulated markets have responsibility for capacity and are required to demonstrate that they can meet this responsibility, but generally speaking there is no affirmative obligation to offer any particular EGU for service.

Decisions by State Regulatory Commissions

When an EGU retirement proposal comes before state regulatory commissions, it is likely to do so in one of the following contexts: "abandonment" proposals or relinquishment of certificates of public convenience and necessity; planning dockets; or special accounting or rate-treatment processes. The value of being able to review retirement proposals is that it provides an opportunity to require a utility to produce a thorough analysis of the potential costs of the proposal and reasonable alternatives, and to subject that analysis to public scrutiny through an administrative proceeding. These processes are briefly described below.

Relinquishment of Certificate of Public Convenience and Necessity

EGUs need regulatory permission to go into service, and they are typically issued a certificate to do so by state utility commissions. These certifications are granted after a commission's public review of the suitability of a proposal, including financial, legal, engineering, and other relevant considerations.

Companies need permission to take EGUs out of service as well, as illustrated below in Vermont's statutory requirements:

> *A company subject to the general supervision of the public service board … may not abandon or curtail any service subject to the jurisdiction of the board or abandon all or any part of its facilities if it would in doing so effect the abandonment, curtailment or impairment of the service, without first obtaining approval of the public service board, after notice and opportunity for hearing, and upon finding by the board that the abandonment or curtailment is consistent with the public interest….*[7]

As the statute indicates, this regulatory review is intended to examine whether or not abandoning an EGU will affect the company's service, specifically calling out

3 ISO New England, Inc. (2012, May 15). *Overview of New England's Wholesale Electricity Markets and Market Oversight*. Internal Market Monitor, pp. 7–8. Available at: http://iso-ne.com/pubs/spcl_rpts/2012/markets_overview_final_051512.pdf

4 See ISO New England Inc. 5th Rev. Sheet No. 7308, FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design Tariff at Section III.13.2.5.2.5: "The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules."

5 In each ISO market, there are also rules (tariffs) that specify how an EGU owner whose de-listing request has been denied will be "made whole" through wholesale market compensation for costs that exceed revenues.

6 A process that was ultimately reviewed and approved by the state utility commission and environmental agency.

7 30 V.S.A. § 231(b). *Certificate of Public Good; Abandonment of Service; Hearing.*

"impairment of service" (i.e., reliability) as a criterion. In an abandonment proceeding, a utility has to demonstrate why its proposal to retire an EGU is in the public interest. It is also an opportunity for the utility commission to provide the public its reasons for granting or denying its approval.

Planning

Utility planning, also referred to as integrated resource planning (IRP), is another context in which a state might review a proposal to retire an EGU.[8] An IRP docket is a public process designed to look broadly at a utility's needs over a certain time period, and to identify the least-cost means of meeting those needs. More specifically, an IRP investigation is a review of various supply- and demand-side options, potential utility plans, and a schedule to monitor and revisit plans as necessary. PacifiCorp, for example, describes its IRP as a:

> *Comprehensive decision support tool and road map for meeting the company's objective of providing reliable and least-cost electric service to all of our customers while addressing the substantial risks and uncertainties inherent in the electric utility business.*[9]

The value in having this structured and comprehensive look forward lies in being able to identify a resource mix before capital is committed to expenditures. This is the case in a traditionally regulated environment in which a utility will seek approval of expenditures. It is also the case in restructured states, where some decisions – transmission expansions, for example – can be shaped or targeted to reflect least-cost, least-risk options.

In the context of EGU retirements, it is also valuable to identify alternatives that avoid raising electric system reliability problems.[10] An IRP's typical "least-cost" criterion implies "the lowest total cost over the planning horizon, given the risks faced" – including reliability. The best resource mix is one that "remains cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution."[11] Planning for EGU retirement is thus an extensive examination of related costs, and costs associated with alternatives. Additional details regarding IRP are provided in Chapter 22.

Tariff Riders and Preapproval

Some state laws provide for the recovery of costs associated with environmental compliance. Given the flexibility granted states by the EPA's proposed Clean Power Plan, an argument could be made that costs related to EGU retirement fit in the category of recoverable costs.

An adjustment clause (also sometimes referred to as a "cost tracker" or "tariff rider") is a separate surcharge (or sur-credit) to incorporate specific costs in rates, independent of overall utility costs and rates established in a general rate case.[12] Utilities in some jurisdictions also enjoy preapproval of expenditures related to environmental compliance.[13] In these cases, utility regulators generally review the proposed plan and the associated budget, and allow cost recovery (barring imprudence in implementing an approved plan[14]). Preapproval is not an uncommon practice and, once obtained, makes cost recovery by the

8 See Chapter 22 for a comprehensive discussion of IRP.

9 PacifiCorp. Integrated Resource Plan website, Overview. Available at: http://www.pacificorp.com/es/irp.html. See also: Lazar, J. (2011, March). *Electricity Regulation in the US: A Guide,* p. 73. Available at: http://www.raponline.org/document/download/id/645, and Farnsworth, D. (2011). *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance,* pp. 20–38, for a more detailed discussion of integrated planning. Available at: www.raponline.org/document/download/id/919

10 US EPA. (2014, June). *Technical Support Document (TSD): Resource Adequacy and Reliability Analysis.* Office of Air and Radiation. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf. The EPA defines the term "resource adequacy" to mean "the provision of adequate generating resources to meet projected load and generating reserve requirements." It defines "reliability" as ensuring the "ability to deliver the resources to the loads, such that the overall power grid remains stable." Reliability Standards for the Bulk Electric Systems of North America, updated December 16, 2014. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

11 Lazar, at supra footnote 9.

12 For a general discussion of adjustment mechanisms, see: Ibid.

13 See discussion of Alabama Power below at footnotes 87–88 and accompanying text.

14 An inquiry into the "prudence" of a decision might focus on such things as failure to consider factors known to management in the original proposal, failure to effectively manage a retrofit process, or failure to reconsider the project as additional cost information becomes available.

utility highly likely.[15] Under Ohio law, for example, an automatic recovery rider allows for utilities to recover the costs of environmental compliance, including "the cost of emission allowances; and the cost of federally mandated carbon or energy taxes…" and a "reasonable allowance for construction work in progress … for an environmental expenditure for any electric generating facility of the electric distribution utility."[16] Regulators need to assess the circumstances and financial impacts of EGU retirements claimed as recoverable costs, especially where preapproval provisions exist.

State 111(d) Compliance Plans

The EPA's Clean Power Plan, proposed in June 2014, would impose a requirement on states to develop a plan for reducing the average CO_2 emissions rate of affected EGUs to specified levels (or "goals") by 2030. The EPA would not require states to include EGU retirements in their plans, but states would have the option to do so. If an EGU has a higher-than-average emissions rate, and the output of the EGU can be replaced with the output from an EGU not affected by the rule or by an affected EGU that has a lower CO_2 emissions rate, the average emissions rate of affected EGUs will decline and the state will be closer to compliance with its emissions goal. This fact, combined with the fact that it is relatively easy to administer and enforce a retirement decision (compared, for example, to other emissions reduction options), may make EGU retirements an option of interest to state air pollution regulators even in the face of the economic complexities that factor into these decisions.

3. State and Local Implementation Experiences

As noted previously, various administrative approaches provide utility regulators with frameworks to analyze potential costs and other relevant factors (such as reliability implications) associated with retirement proposals. The examples below – reflecting both restructured and traditionally regulated states – show that the exact process states use to analyze proposals may be less important than the willingness to take an integrated approach and thoroughly consider alternatives.

In 2011 the state of Colorado, a traditionally regulated state, used a process similar to IRP in implementing 2010 legislation that proposed, among other things, EGU retirements. The "Clean Air – Clean Jobs Act" (the Act) passed in April 2010 anticipated new EPA regulations for criteria air pollutants (nitrogen oxide [NO_X], sulfur dioxide [SO_2], and particulates), mercury, and CO_2.[17] It required:

> *[b]oth of the state's two rate-regulated utilities, Public Service Company of Colorado (PSCo), and Black Hills/ Colorado Electric Utility Company LP … to submit an air emissions reduction plan by August 15, 2010, that cover[s] the lesser of 900 megawatts or 50% of the utility's coal-fired electric generating units.*[18]

The two Colorado utilities developed these required plans and gained the approval of the PUC and state air regulators on an extraordinarily rapid schedule. Their approved plans were then included in a state implementation plan (SIP) submitted by the state to the EPA. As a result, two coal-fired power units totaling more than 210 megawatts (MW) have been retired and repowered, and three additional units are expected to be retired and repowered by 2017. Formal IRP implementation is typically an ongoing, multiyear process; this effort, from signed legislation to EPA approval of

15 Although some states allow for preapproval as a matter of law or administrative practice, others insist that decision-making is a management responsibility and will only review the actions of management when an investment is completed and goes into service. Utility regulators reach their own conclusion on this issue, guided by state law and regulatory precedent.

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

17 In addition to anticipating new EPA regulations for criteria air pollutants including CO_2, it requires a utility to (1) consult with the Colorado Department of Public Health and Environment on its plan to meet current and "reasonably foreseeable EPA clean air rules," and (2) submit a coordinated multipollutant plan to the state PUC.

18 Memorandum from the Office of Legislative Legal Services to Legislative Counsel, March 16, 2011, re: H.B. 10-1365 and Regional Haze State Implementation Plan. Available at: http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/$File/SIPMeetingMaterials.pdf

Colorado's SIP changes, took approximately 30 months.[19]

It is often the case that a proposal to retire a power plant can itself change over the course of the proposal's review, as was the case with Nevada's Mohave Generating Station and Oregon's Boardman Plant. In some cases, the proposal to close can be amended and become a proposal to repower.

In 1999, the owners[20] of the Mohave Generating Station – a two-unit, 1580-MW coal-fired power plant built between 1967 and 1971 – executed a consent decree to either install SO_2 controls or close the plant by 2005.[21] In 2003, Southern California Edison approached the California PUC for approval of preliminary engineering costs for a retrofit.[22] After an extended hearing, the California PUC ordered a comprehensive review of the future of the Mohave project.[23] The Mohave Alternatives and Complements Study was completed in 2005. It examined alternatives to a retrofit of Mohave, found a wide variety of cost-effective options, and at the conclusion of the study, the Mohave plant was closed permanently on December 31, 2005.[24]

Oregon's 550-MW coal-fired Boardman plant was originally expected to operate until 2040. However, to comply with state and federal environmental regulations, in 2010 Boardman was required to install approximately $500 million of pollution control equipment by 2017. In early 2010, owner Portland General Electric (PGE) announced that it was considering an alternative plan for Boardman that would retire the plant in 2020. PGE asked regulators to allow it to make a $45 million investment by 2011 to partially clean up Boardman's emissions of mercury and NO_X, and then operate the plant until 2020.[25] In June 2010, Oregon's Environmental Quality Commission rejected PGE's proposal to close Boardman by 2020, stating that Oregon's Environmental Quality Commission did not oppose early shutdown of the plant, but only wanted to do so using the best options possible.[26] PGE proceeded to look at other ways to close the plant by 2020, including alternative levels of investment in controls and different closure dates. The company concluded that earlier closure than 2020 was not an option because that time was needed to develop alternatives for the power produced. Later in 2010, PGE filed its Integrated Resource Plan with the Oregon PUC, stating that the 2020 shutdown was its preferred option.[27] On the basis of its IRP analysis, PGE ultimately proposed termination of coal use at Boardman at the earliest date that the utility felt resulted in adequate reliability for its customers: 2020. After reviewing various alternatives, the Oregon PUC acknowledged this approach in its order on

19 The Act was signed into law in April 2010, a Commission docket was opened in May, and a final order was issued in December. In January 2011 the Colorado Department of Public Health and Environment adopted changes and the EPA approved the new Colorado SIP in September the following year. NARUC Climate Policy Webinar 3: State Case Studies. (2010, December 17). *Dispatches from the Front: The Colorado Clean Air-Clean Jobs Act.* Ron Binz, Chairman, Colorado Public Utilities Commission. Available at: http://www.naruc.org/Publications/Binz%20TFCP%20Presentation%20121710.pdf; NARUC Task Force on Climate Policy Webinar. (2011, March 11). *Coal Fleet Resource Planning: How States Can Analyze their Generation Fleet.* Colorado Case Study. Karen T. Hyde, Vice President, Rates & Regulatory Affairs, & Jim Hill, Director, Resource Planning and Bidding; Xcel Energy. Available at: http://www.naruc.org/domestic/epa-rulemaking/default.cfm?more=3

20 Southern California Edison was the majority owner (56 percent) of the plant. The Los Angeles Department of Water and Power (10 percent), Nevada Power Company (14 percent), and Salt River Project (20 percent) were the other owners.

21 Grand Canyon Trust, the Sierra Club, and National Parks Conservation Association sued the owners of Mohave because of haze over the Grand Canyon and other air pollution that was caused by the plant.

22 Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12016 Report Prepared for Southern California Edison SL-008587. (2006, February).

23 The California Public Utilities Commission ordered Southern California Edison to perform for them a study of alternatives for replacement or complement of its share of the Mohave Generating Station under Decision 04-12-016, issued on December 4, 2004.

24 Edwards, J. (2009, June 6). Laughlin Coal-Fired Power Plant Going Away. *Las Vegas Review-Journal*. Available at: http://www.reviewjournal.com/business/laughlin-coal-fired-power-plant-going-away

25 PGE was also considering using biomass to continue operating the plant after ending its use of coal.

26 Sickinger, T. (2010, June 28). DEQ Proposes New Options for Shutdown of PGE Coal Plant. *The Oregonian.*

27 During the pendency of the IRP process, the plant owners made additional investments that the Oregon PUC considered in its final decision.

PGE's IRP.

In jurisdictions that have restructured their utility sector, generation is considered a competitive service that is no longer subject to regulatory review or treatment. When Ohio restructured, for example, generators were given a choice to continue to be traditionally regulated by the PUC or to participate in a largely deregulated wholesale market. In 2010, Ohio Power sought approval for a rate adder in order to recover an unamortized plant balance of $58.7 million on its retiring 450-MW Sporn Unit 5, under the same statute that provided an automatic recovery rider for traditionally regulated facilities.[28] The Sporn Plant, however, had chosen to operate in the deregulated market, so the PUC denied its request for cost recovery for closure-related costs.

In many cases, EGU retirements are tied to approval of proposals to convert and repower them with another fuel.[29] Indianapolis Power & Light Company (IPL), for example, conducted an integrated analysis ahead of its proposal to the Indiana Utility Regulatory Commission to repower Harding Street Generation Station Unit 7 from coal to natural gas as part of the company's "overall wastewater compliance plan for its power plants."[30] The Commission had already approved IPL's proposal to convert Harding Street Units 5 and 6 from coal to natural gas. Unit 7's conversion would conclude the closing of all of IPL's coal units at Harding Street by 2016, a move that the company says, "would reduce IPL's dependence on coal from 79 percent in 2007 to 44 percent in 2017…."[31] This plan was motivated not only by IPL's need to comply with Clean Water Act requirements; these closures will enable IPL to close Harding Street Generation Station's coal pile and ash ponds, which are subject to Resource Conservation and Recovery Act (RCRA) solid waste rules.

4. GHG Emissions Reductions

EGU retirements that occur in response to GHG regulations have the potential to avoid significant amounts of GHG emissions. The retirement of coal, oil, or inefficient natural gas capacity will not only reduce GHG emissions, but also emissions of other regulated air pollutants, depending on the fuels burned at a retiring EGU.

CO_2, methane, and nitrous oxide emissions are all produced during coal combustion; nearly all of the fuel carbon (99 percent) in coal is converted to CO_2 during the combustion process.[32] This conversion is relatively independent of firing configuration.[33] Consequently, the level of avoided emissions available from a coal plant retirement will vary only slightly, depending on the operating characteristics of each unit, but more so based on the type of coal normally used at the plant. CO_2 emissions for coal are linked to carbon content, which varies between the classes of bituminous and subbituminous coals. As a consequence, there is a significant range in emissions factors within and between ranks of coal (Table 8-1).

Table 8-1

Average Input Emissions Factors of Coal[34]

Coal Type	Input Emissions Factor (lb CO_2/MMBTU)
Coal – Anthracite	227
Petroleum Coke	225
Coal – Lignite	212 to 221
Coal – Subbituminous	207 to 214
Coal – Bituminous	201 to 212

28 In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider, Case No. 10-1454-EL-RDR, Finding and Order at 19. (2012, January 11). Ohio Revised Code, Section 4928.143(B) (2) (a) and (b).

29 Repowering of existing EGUs is examined in Chapter 9.

30 IPL Power. (2014, August 15) IPL plans to stop burning coal at Harding Street Generation Station in 2016; Utility to seek approval to switch power generation from coal to natural gas. [Press release]. Available at: http://www.indianadg.net/ipl-announces-plans-at-harding-street-plant-to-switch-from-coal-to-natural-gas-in-2016/

31 Ibid.

32 AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources, 1.1 Bituminous And Subbituminous Coal Combustion. Available at: http://www.epa.gov/ttn/chief/ap42/ch01/index.html

33 Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced.

34 Based on: US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf

The majority of the fuel carbon not converted to CO_2 is entrained in bottom ash. Furthermore, carbon content also varies within each class of coal based on the geographical location of the mine. Methane emissions also vary with the type of coal being fired and the firing configuration, but are highest during periods of incomplete combustion, such as the start-up or shut-down cycle for coal-fired boilers.

Several utilities and operators of coal-fired power plants have already announced retirements. In late 2013, the Tennessee Valley Authority announced the retirement of eight coal-fired units totaling 3000 MW of capacity at three different plant sites.[35] These eight units include:

- All five coal-fired units in its Colbert, Alabama plant location, representing CO_2 emissions of 6.5 million tons in 2010;
- Unit 8 at Widow's Creek, Alabama, with 2010 CO_2 emissions of 3.3 million tons; and
- The smaller two of three units at Paradise, Kentucky with combined 2010 CO_2 emissions of 8.9 million tons.[36]

South Carolina Electric and Gas announced the closure of its 295-MW unit at Canadys station in November 2013,[37] completing the retirements of all units at this plant. The other two units at Canadys were closed by South Carolina Electric and Gas in 2012. In 2010, combined CO_2 emissions from these three units totaled 14 million tons.

Coal plant retirements have also been announced in restructured electricity markets. Energy Capital Partners, operators of the Brayton Point plant in Massachusetts, announced plans to close Units 1–3 of this plant when its supply agreements with ISO New England expire in May 2016.[38] In 2010, CO_2 emissions from Units 1–3 were 6.3 million tons.

SourceWatch, a project of the Center for Media and Democracy, has prepared an assessment of expected coal EGU retirements by size and year, starting with 2009 as the first year.[39] The list of planned retirements is constantly changing, which means that any assessment of the total capacity of expected retirements soon becomes outdated. For example, the Government Accountability Office (GAO) estimated in August 2014 that more than 42 gigawatts (GW) of coal capacity had either been retired since 2012 or was planned for retirement by 2025. This estimate in 2014 exceeded the high end of the range of expected retirements cited by GAO in a similar 2012 report.[40]

As for the aggregated impact of EGU retirements on CO_2 emissions, it must first be understood that EGUs vary in their output and their emissions from year to year. It is easy to assess the historical CO_2 emissions of a retiring unit in a particular baseline year, as the previous examples demonstrate. However, such estimates tend to vary in their selection of baseline year and in any event become quickly out of date. Although the number of units and the aggregated capacity of expected retirements is large, the units that have thus far retired or announced plans to retire tend to mostly be smaller EGUs or EGUs that operate less frequently. The largest, most frequently operated coal EGUs produce the lion's share of coal-fired generation, and few of these units are slated for retirement. Because of these factors, assessments of the reduction in coal-fired EGU emissions that will result from retirements generally represent less than ten percent of total EGU emissions.[41] Furthermore, it must also be understood that retiring units can be replaced by a variety of types of resources, or not replaced at all, and the net emissions reductions attributable to EGU retirement decisions are rarely assessed in a consistent or rigorous way.

35 Tennessee Valley Authority. (2013, November). TVA Board Takes Action to Improve TVA's Operations and Financial Health. [Press release]. Available at: http://www.tva.com/news/releases/octdec13/board_111413.html

36 All emissions data are obtained from the EPA's eGRID database, which can be accessed or downloaded at http://www.epa.gov/cleanenergy/energy-resources/egrid/

37 South Carolina Electric and Gas. (2013, November). SCE&G Retires Canadys Station Power Plant as Part of Strategy to Meet More Stringent Environmental Regulations. [Press release]. Available at: https://www.sceg.com/about-us/newsroom/2013/11/13/sce-g-retires-canadys-station-power-plant-as-part-of-strategy-to-meet-more-stringent-environmental-regulations

38 US Energy Information Administration. (2014, March 20). *Today in Energy*. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15491

39 SourceWatch.org. *Coal Plant Retirements*. Available at: http://www.sourcewatch.org/index.php/Coal_plant_retirements#Projected_retirements_range_from_25.2C000_-_60.2C000_megawawatts

40 GAO. (2014, September). *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*. Available at: http://www.gao.gov/assets/670/665325.pdf

41 See, for example, an assessment reported by *USA Today* at: http://www.usatoday.com/story/money/business/2014/06/08/coal-plant-retirements-barely-cut-carbon-emissions/10008553/

5. Co-Benefits

In addition to the GHG emissions reductions noted previously, EGU retirements will likely result in reductions in emissions of other regulated air pollutants, depending on the fuels burned prior to retirement and the resources used to replace the power generated by the retired EGUs.

The full range of co-benefits that can be realized through EGU retirement are summarized in Table 8-2. The non-GHG air quality benefits are based on an assumption that any plant that is closed will be replaced by either a more efficient fossil-fueled plant, renewable energy, energy efficiency, or a combination of these resources, but the magnitude of the benefits can be expected to vary widely depending on the new resource.

Table 8-2

Types of Co-Benefits Potentially Associated With Retiring Aging Power Plants

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes – for coal-fired EGUs
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	Maybe
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	Maybe
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	No
Other: Alternative Land Use	Yes

6. Costs and Cost-Effectiveness

It is common business practice to make decisions based on forward-looking costs, the costs one reasonably expects to confront in the future. A decision to close an EGU is no different, except the costs are measured in millions or billions of dollars, not thousands.[42] As one commentator noted:

> *In general, the owner of a coal-fired power plant (or of any generating facility, for that matter) may decide to retire the plant when the revenues produced by selling power and capacity are no longer covering the cost of its operations. While sometimes these decisions are complex, they essentially can resemble the basic choices that households face, for example, when they have to decide whether making one more repair on an old car is worth it: often, making the repair is more expensive and risky than the decision to trade in that car and buy a new one with better mileage and other features that the old car lacks.*[43]

The costs and cost-effectiveness of an EGU retirement proposal will depend on a number of unique factors related to the physical plant in question, the costs that it is reasonably likely to incur in the future, and regulatory treatment of incurred costs.

Environmental Regulatory Factors

In addition to being subject to standards for GHG emissions under section 111(d) of the Clean Air Act, existing fossil generation sources will be subject to additional environmental regulatory requirements in coming years. The EPA has recently developed regulations under its Clean Water Act and RCRA authority that would

42 Lazar, J., & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates, Working to Ensure Affordable Compliance With Public Health and Environmental Regulations.* Available at: www.raponline.org/document/download/id/4670

43 Tierney, S. F. (2012, February 16). *Why Coal Plants Retire: Power Market Fundamentals as of 2012.* Analysis Group, Inc. p 2. Available at: http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/2012_Tierney_WhyCoalPlantsRetire.pdf

apply to fossil generators subject to the EPA's Clean Power Plan. Clean Water Act regulations focus on cooling water structures at EGUs, and EGU toxic effluent discharges. RCRA regulations apply generally to solid waste production and containment, in this case, to coal combustion residuals. In addition to promulgating water and solid waste regulations, the EPA has or can be expected to develop a number of standards and regulations under its Clean Air Act authority, including updated National Ambient Air Quality Standards, the Cross-State Air Pollution Rule, and the MATS.[44] For example, the EPA is expected to finalize a revised, more stringent National Ambient Air Quality Standards for ground-level ozone in 2015.

A review of specific compliance costs associated with these environmental programs is beyond the scope of this discussion. However, an integrated review of potential environmental compliance costs would be an appropriate part of the analysis a state might conduct in response to an EGU retirement proposal, inasmuch as the EGU's economic viability and suitability as a utility asset could be affected.

Market Factors

A brief review of market factors may also be instructive for regulators in understanding the role that markets play as they analyze Clean Power Plan compliance options and prepare to make informed decisions on potential EGU retirement proposals. It is important to note, however, that fuel prices and quantities are volatile and are likely to change in the future. After a low in 2012, for instance, natural gas prices have rebounded, as shown in Figure 8-1. Increased domestic natural gas supplies are expected to result in relative price stability and continue to allow gas to compete effectively with other fuels. US coal exports also declined recently owing to a slowing of the Chinese economy and caps placed on the consumption of coal by many Chinese cities and provinces as a way to improve air quality.

The owners of EGUs will consider market factors, including current and projected fuel prices, as part of any retirement or investment decision. A decision to retire a coal-fired EGU that seems cost-effective when coal prices are high and gas prices are low, for example, might not be cost-effective if market conditions change.

Decreasing Cost of Natural Gas

Declining natural gas prices over the past several years owing to the availability of shale gas made available through more effective drilling techniques have made natural gas-fired EGUs more competitive, and this has been a factor in decisions of EGU owners to retire or idle coal plants.[45] Although a number of factors coalesced to cause recent low gas prices,[46] however, other factors suggest that current prices may not necessarily be sustainable.[47]

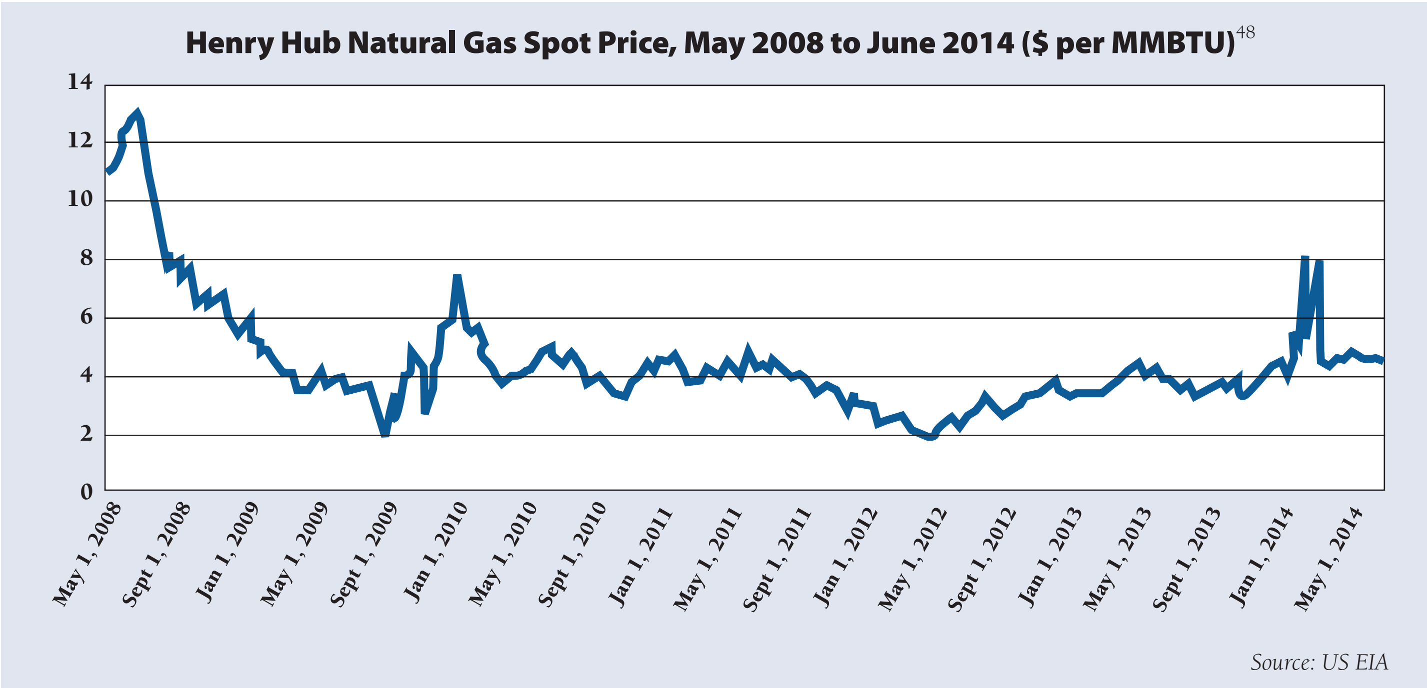
44 The US Energy Information Agency reports that, between 2012 and 2020, approximately 60 GW of coal-fired capacity is projected to retire in the AEO2014 Reference case, which assumes implementation of the MATS standards, as well as other existing laws and regulations. Supra footnote 38.

45 Gerhard, J. (2013). *Coal Plant Closures and US Wholesale Electricity Markets.* In Regulatory Assistance Project Knowledge Management Series (2013). *Complying With Environmental Regulations.* Available at: http://www.raponline.org/featured-work/complying-with-environmental-regulations-a-knowledge-management

46 Including reduced demand owing to economic recession; shale gas production from early high-production sites and gas dumping; price subsidization of dry gas from high "wet gas" and "liquids" prices; the "non-winter" of 2011/2012 (the first four months of 2012 were the warmest January to April in US recorded history); residential and commercial natural gas consumption down more than 18 percent; and gas storage at record levels, and nearing capacity. See: Kushler, M. (2013, October 23). *Natural Gas Prices and Natural Gas Energy Efficiency: Where Have We Been and Where Are We Headed.* Presentation to the Energy Foundation Advocates Meeting, ACEEE. Kushler, M., York, D., & Witte, P. (2005, January). *Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest.* ACEEE, p 5. Available at: http://www.aceee.org/research-report/u051

47 Including increased exports of domestic gas, and gas/electricity interdependence, that is, the greater share of gas-fired electricity production and the risk associated with seasonal demand spikes and storage miscalculation. See, e.g.: Farnsworth, D. (2014). *Further Preparing for EPA Regulations.* Appendix 1 and discussion of natural gas cost risk at pp. 48–52. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6989

Figure 8-1



Excess Natural Gas Generation Capacity

Another factor weighing on the closure of coal plants is the significant amount of underused natural gas generating capacity in the United States. According to a 2011 Massachusetts Institute of Technology study, the existing US natural gas generation fleet has an average capacity factor of approximately 41 percent, whereas its design capacity allows such plants to operate at 85 percent.[49] The EPA, in its analysis supporting the Clean Power Plan proposal, concluded that existing combined-cycle gas plants could reliably operate at an average capacity factor of 70 percent.[50] This unused capacity is sufficient surplus to displace roughly one-third of US coal generation.[51] Thus, as the cost of natural gas comes down, underutilized gas plants have available capacity with which to compete with coal plants and possibly displace them in the dispatch order.[52]

Inherent Efficiency of Natural Gas Plants

Modern natural gas-fueled combined-cycle units are generally more efficient than existing coal plants. Coal and combined-cycle gas plants typically have heat rates of 10,000 BTU/kilowatt-hour (kWh) and 7000 BTU/kWh, respectively. To the degree that coal and gas costs converge, the more efficient natural gas plants will become more economically competitive than their coal counterparts.[53]

Increasing Cost of Coal

Increasing coal costs put additional pressure on the ability of US coal plants to participate in US electricity markets.[54] In many cases, mining and mining-related regulatory requirements have increased, contributing to higher mining costs that are passed along to coal consumers and the closure of some mines. Most notably, however, coal prices have increased every year since 2002, and have done

48 NGA Issue Brief: Natural Gas Price Trends. (2014, August). *Henry Hub Natural Gas Spot Price, May 2008 to June 2014 ($ per MMBtu)*. Available at: http://www.northeastgas.org/nat_gas_price_trends.php

49 Supra footnote 45.

50 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions From Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents

51 Ibid.

52 Supra footnote 45.

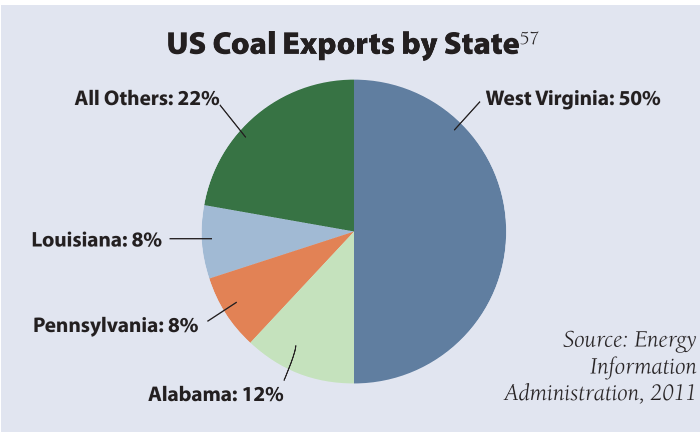
53 Ibid.

54 Ibid.

so in part because of increased exports,[55] particularly to European and Asian markets, and in part because of recent reductions in production in other parts of the world, such as Australia and Indonesia.[56]

According to the National Mining Association, US coal exports increased 31 percent from 2010 to 2011.[58] The average price per ton of coal in 2011 was up 24 percent over 2010, and coal exports represented 9.8 percent of all US coal production in 2011.[59] According to *The Wall Street Journal*, "US coal shipments outside the country in 2014 are expected to surpass 100 million tons for the third year, a record string"[60] (Figure 8-3).

Figure 8-2



Increasing Cost to Transport Coal

The cost of transporting coal to coal-fired generators raises generator costs and can make them less economical to run.[62] Coal plants receive approximately 72 percent of their coal by rail.[63] Costs can range anywhere from 10 percent to almost 70 percent of the delivered price of coal, depending on the type of coal purchased and location of the power plant.[64] The US Energy Information Administration (EIA) reports that rail transportation costs increased from $13.04 to $15.54 per ton (19 percent) from 2001 to 2010.[65] Competition for rail capacity from tight oil producers has exacerbated shipping costs for coal generators.

Figure 8-3

55 Miller, J. W. (2014, March). The New Future for American Coal: Export It. *Wall Street Journal*. Available at: http://online.wsj.com/news/articles/SB10001424052702303563304579447582374789164.

56 Supra footnote 45.

57 Department of Transportation, Federal Highway Administration. (2013). *National Gateway and Corridor Concepts*. Available at: http://www.fhwa.dot.gov/planning/border_planning/gateways_and_corridors/gateway_ops/sec03.cfm (DOT FHWA 2013).

58 Coleman, L. (2012, May). *2011 Coal Producer Survey.* National Mining Association. Available at: http://nma.dev2.networkats.com/pdf/members/coal_producer_survey2011.pdf; Supra footnote 45.

59 Supra footnote 45.

60 Supra footnote 55.

61 Ibid.

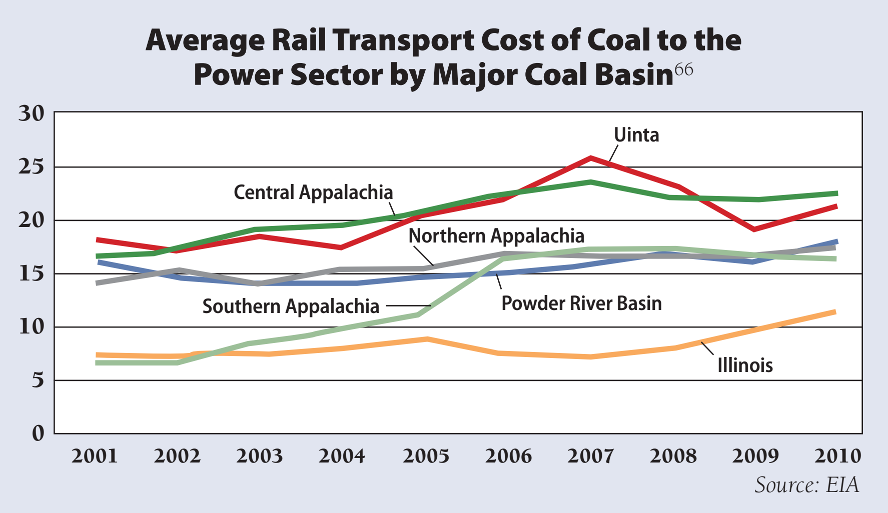
62 Supra footnote 45.

63 Ibid.

64 Ibid.

65 Ibid.

Figure 8-4



sales … declined in four of the past five years," driven by declining industrial sales and flat sales in the residential and commercial sectors.[70] This occurred "despite growth in the number of households and commercial building space." And, "The only year-over-year rise in electricity use since 2007 occurred in 2010, as the country exited the 2008-09 recession"[71] (Figure 8-5).

Increasing Competitiveness of Renewable Energy

Several observers have noted that downward trends in the costs of renewable energy are now reaching the point at which they are placing pressure on coal plants at certain times in the year and replacing some coal plants in the dispatch stack.[72] For example, the Analysis Group has

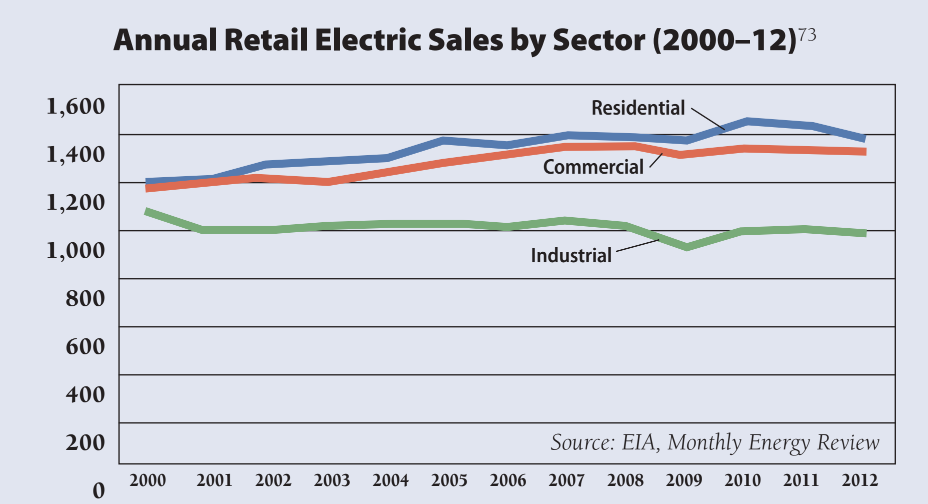
Age of Coal Plant Fleet

Another factor that weighs into the decision to retire coal plants is that many of the coal plants under consideration are at or near the end of their economically useful lives.[67] These units tend to have higher fixed and variable operation and maintenance (O&M) costs per megawatt-hour of electricity generated, to be less efficient in generating electricity, and to be more expensive to retrofit than newer units.[68]

Flat or Decreasing Electricity Demand

The recent economic downturn and ongoing investments in end-use energy efficiency are combining to flatten load growth and moderate demand for electricity. This in turn lowers potential revenues to generators.[69] In December 2013, the EIA found that "US electricity

Figure 8-5



Note: Direct electricity usage and sales to the transportation sector are not graphed as both account for less than 4% of electricity usage.

66 Association of American Railroads. (2013, August). DOT FHWA 2013. The nation's rail system is a key part in US coal-fired electricity production. According to the Association of American Railroads, coal accounted for nearly 20 percent of rail gross revenue in 2013. https://www.aar.org/ See also: Association of American Railroads. (2014, July). *Railroads and Coal.* Available at: https://www.aar.org/BackgroundPapers/Railroads and Coal.pdf#

67 Supra footnote 45; *Air Emissions and Electricity Generation at US Power Plants.* (2012, April 18). Available at: http://www.gao.gov/assets/600/590188.pdf

68 Depending on the regulatory treatment of coal plant costs, plants may or may not be fully depreciated. See discussion below of "Other Regulatory Factors."

69 Supra footnote 45.

70 US EIA. *Annual Retail Electric Sales by Sector (2000–12).* Today in Energy. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=14291

71 Supra footnote 70.

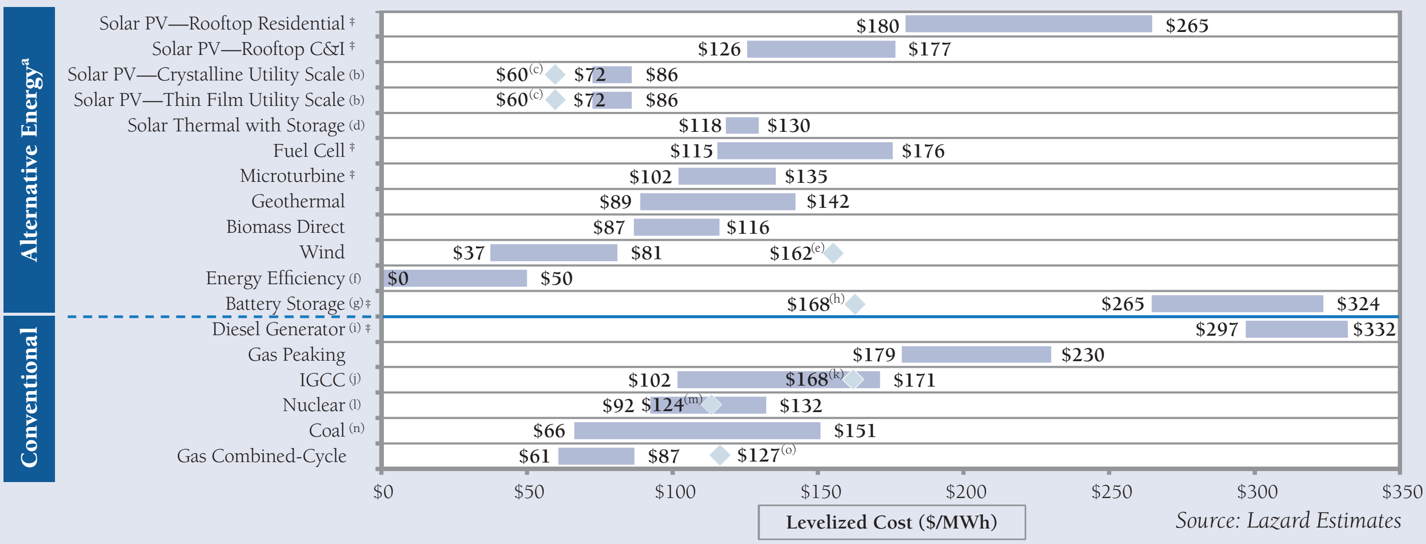
72 Supra footnote 45.

73 Supra footnote 70.

noted that renewables and other distributed resources made up approximately ten percent of PJM's 2014–2015 capacity auction, displacing other generation resources and contributing to "the economic pressure on existing generating resources."[74] In particular, the levelized cost of electricity produced by wind and solar resources dropped by more than 50 percent from 2008 to 2013.[75] Lazard's most recent Levelized Cost of Energy Analysis reveals continuing and significant competitive price improvements of certain renewables against other more traditional resources, as summarized in Figure 8-6. A Deutsche Bank analyst has forecast that by 2016, solar prices will be

Figure 8-6

Lazard's Estimates of Unsubsidized Levelized Cost of Energy (Dollars per MWh)[76]



Source: Lazard Estimates

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost for conventional and Alternative Energy generation technologies. Assumes Powder River Basin coal price of $1.99 per MMBtu and natural gas price of $4.50 per MMBtu. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d).

‡ Denotes distributed generation technology.

a. Analysis excludes integration costs for intermittent technologies. A variety of studies suggest integration costs ranging from $2.00 to $10.00 per MWh.

b. Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW system in high insolation jurisdiction (e.g., Southwest US). Not directly comparable for baseload. Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

c. Diamond represents estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system.

d. Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

e. Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.

f. Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely. Estimates involving demand response may fail to account for opportunity cost of foregone consumption.

g. Indicative range based on current stationary storage technologies; assumes capital costs of $500 – $750/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% – 85% and fixed O&M costs of $22.00 to $27.50 per KWh installed per year.

h. Diamond represents estimated implied levelized cost for "next generation" storage in 2017; assumes capital costs of $300/KWh for six hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% and fixed O&M costs of $5.00 per KWh installed per year.

i. Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of $4.00 per gallon.

j. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

k. Represents estimate of current US new IGCC construction with carbon capture and compression. Does not include cost of transportation and storage.

l. Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

m. Represents estimate of current US new nuclear construction.

n. Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

o. Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

74 Supra footnote 43.

75 Silvio Marcacci. (2013, September 20). Analysis: 50 Percent Reduction In Renewable Energy Cost Since 2008. Commentary on "Lazard's Levelized Cost of Energy Analysis—Version 7.0." The Energy Collective. [Web log post]. Available at: http://theenergycollective.com/silviomarcacci/276841/analysis-50-reduction-cost-renewable-energy-2008

76 Lazard, J. (2014, September). *Lazard's Levelized Cost of Energy Analysis – Version 8.0.* Available at: http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

competitive with or lower than those of average power prices in 36 states; solar is already competitive today in ten states.[77]

Poor Load Forecasting

One source cited poor load forecasting as a reason some plants may be retired, saying, "As changes in demand and the economy evolved, some utilities acknowledged weaknesses in the forecast models used by the industry to project future electricity use. When overstated load forecasts were identified, the new plant was no longer viable."[78]

The previous discussion illustrates that numerous forward-looking market factors affect plant closure decisions by plant owners and regulators. Understanding the role of these factors can help in weighing the relative merits of plant closure proposals, because the central question facing regulators is whether plant closures are cheaper and less risky than alternative compliance options.

7. Other Considerations

As the prior discussion illustrates, the cost-effectiveness of a plant closure proposal needs to be determined on a case-by-case basis, but there are some useful general observations that can be made. Older power plants in many ways are at a disadvantage when compared to newer generation resources. In a market context, retirement is considered when the potential income for the unit is no longer sufficient to justify the unit's continued O&M. This may be attributable to such factors as fuel costs, regulatory pressure, or costs of required controls that combine, making it no longer economically justifiable to continue to maintain the unit in operable condition.

Comparative fuel costs and underutilized and more efficient capacity all contribute to the inability of older generating resources to compete economically. This is why conventional wisdom holds that old power plants are more suitable for retirement. For example, a plant's age was a major factor in a 2013 M.J. Bradley and Associates analysis of pending coal retirements in which it found that most of the 52 GW of coal units slated for retirement by 2025 are "small in size, lack environmental controls, and are over 50 years old"[79] (Table 8-3). In 2012, the US GAO reached similar conclusions in "Air Emissions and Electricity Generation at US Power Plants," a study that examines older EGUs.[80]

Although utility decisions related to plant closure are largely driven by the age of a power plant, they are also heavily influenced by whether or not a company will be able to recover a plant's undepreciated costs – despite the

Table 8-3

Coal Retirements as of March 2013 [81]

Characteristic	Announced for Retirement (since January 2006) by 2025	Overall US Fleet
Capacity	52 GW	322 GW
Units	340	1264
Unit Age (avg)	54 years	43 years
Unit Size (avg)	153 MW	254 MW
Utilization (avg in 2011)	49%	71%
Regulated (% of capacity owned by vertically integrated utilities)	70%	75%

77 Walton, R. (2014, October 30). *Study: At Least 36 States Will See Solar Hit Grid Parity by 2016.* Utility Dive. Available at: http://www.utilitydive.com/news/study-at-least-36-states-will-see-solar-hit-grid-parity-in-2016/327286/

78 Supra footnote 45.

79 Saha, A. (2013, April 12). *Review of Coal Retirements.* M.J. Bradley & Associates, LLC. Available at: http://www.mjbradley.com/reports/coal-plant-retirement-review

80 US GAO. (2012, April 18). *Air Emissions and Electricity Generation at US Power Plants.* Available at: http://www.gao.gov/assets/600/590188.pdf. In this study the US GAO defines "older plants" as having been in operation "in or before 1978."

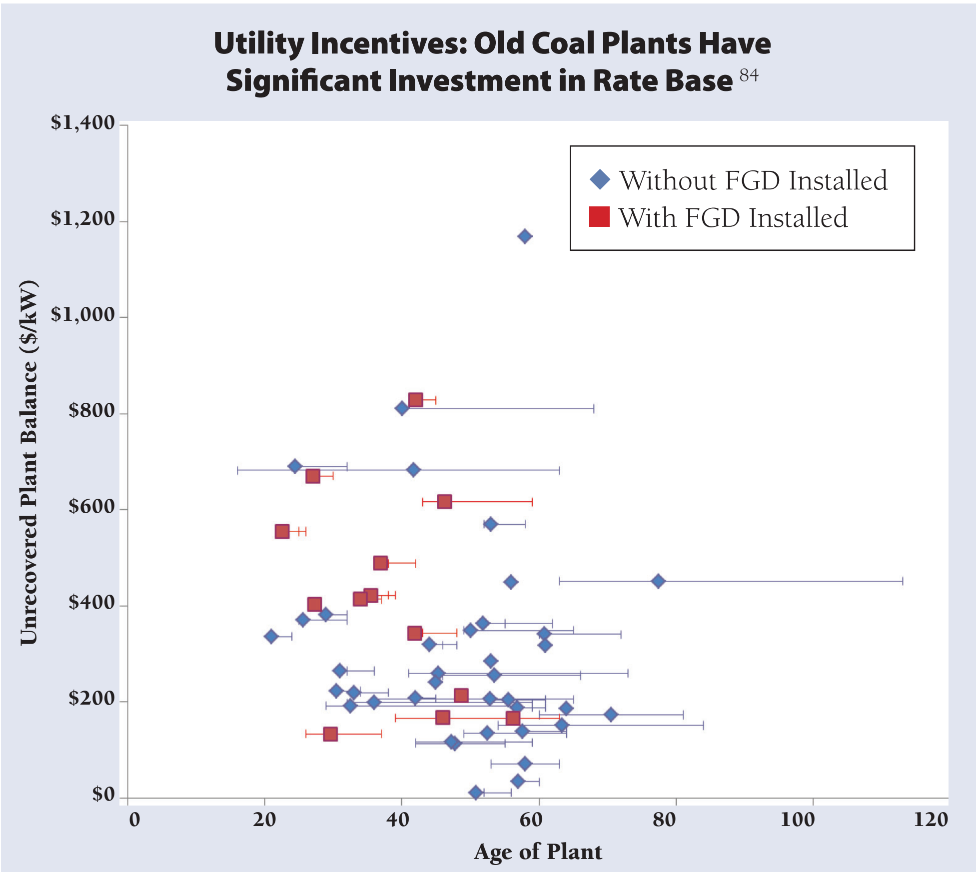
81 Based on *Coal Retirements,* in: supra footnote 79.

plant's age.[82] Plant owners are understandably reluctant to face such "stranded costs" where they lack certainty of recovery from ratepayers.

Nationwide information on plant depreciation is not readily available because depreciation studies are typically confidential. But based on one sample derived from non-confidential studies, plants may have hundreds of dollars per kilowatt of unrecovered value on the books, as illustrated in Figure 8-7.[83]

In this sample, comprising 52 coal plants owned by 11 utilities, the average plant age (weighted by capacity) is approximately 47 years. Average plant capacity is approximately 675 MW. Average unrecovered plant balance is approximately $336/kilowatt. And the unrecovered balance is over 50 percent of total plant balance.

Figure 8-7



As noted earlier, older plants are less likely to be dispatched, and if they are not running, then they are at risk of not recovering their fixed operations and maintenance costs and undepreciated plant costs, an untenable outcome from both an economic and regulatory perspective. Not only are older plants more likely to be producing less revenue, typical regulatory practice for utility-owned generating units requires those investments to be "used-and-useful" in order to be recovered in utility rates.[85] Although a used-and-useful determination is complex and fact-specific, there are some general observations relevant to power plant closures that can be made with regard to this doctrine.[86]

82 See, e.g.: Wishart, S. (2011, September 27). *Coal Retirement vs. Refurbishment – The Role of Energy Efficiency.* Delivered at ACEEE National Conference on Energy as a Resource. Available at: http://aceee.org/ Important economic drivers for coal retrofit versus retirement include: costs of environmental controls (capital and O&M), replacement capacity; replacement energy; CO_2 assumptions; current rate base; and accelerated depreciation.

83 Synapse Energy Economics collected information from 52 coal plants owned by 11 companies.

84 Biewald, B. (2014, January 21). *The Future of Coal: Economics and Planning.* Synapse Energy Economics. Available at: http://www.synapse-energy.com/Downloads/SynapsePresentation.2014-01.0.Future-of-Coal.S0091.pdf

85 Lazar 101 at 39. Electricity prices are set by utility commissions in rate cases. In these investigations, commissions review company costs, including those associated with power plant investment, and determine which are appropriate and suitable for recovery in rates. In rate cases, companies justify their costs, which can include expenses associated with fuel, O&M, purchased power, and other administrative-related activities. These considerations only apply to utility-owned generating units. Generating units that are owned by independent power producers and operating in a wholesale market will make retirement decisions based on whether potential income for the unit is sufficient to justify the unit's continued O&M, as previously noted.

86 When a new power plant enters service and its costs are considered for inclusion in rates, regulators often perform a "prudence review" to determine if the plant was built in an economic manner. If regulators determine that the planning or construction was imprudent, they can disallow a portion of the investment, and refuse to include it in the company's rate base. Lazar at 39.

For a facility to be considered "used" means that the facility is actually providing service. Being "useful" means that without the facility, either costs would be higher or the quality of service would be lower.[87] In rate investigations, the utility has the burden of proving that an investment meets this test, but utilities often enjoy the presumption of used-and-usefulness in the absence of evidence to refute it.[88] In circumstances in which plant investment is found to not be used-and-useful, its costs are not allowed in utility rates. This is one reason plant closure is such a sensitive topic. Companies with generating units that are marginal and barely operational are at risk of being determined to not be used-and-useful. And companies do not want to see this happen, because it will directly compromise their ability to receive the full recovery of their investment.[89]

Not surprisingly, finding a plant to not be used-and-useful also poses political and economic ramifications for utility commissions and public advocates. This is why commissions may only respond obliquely to utilities in this regard. Commissions might observe, for example, that the economics of a plant are questionable. They might provide "signals" to utilities about the propriety of making further investments in a plant, perhaps suggesting that if an investment is undertaken the commission will take a "hard look" at that utility decision, or if there are related cost overruns, the company's shareholders and not the ratepayers can be expected to shoulder these costs.

An additional observation: the previous discussion has described "typical" regulatory practice. A plant closure undertaken for purposes of compliance with a Clean Air Act requirement may not be typical. This is a significant distinction that companies may make and that utility commissions could take into consideration. For example, although granting recovery of costs that would otherwise not be deemed used-and-useful is not recommended, an investigation might conclude that granting recovery of undepreciated costs associated with the retirement of older power plants is a more cost-effective approach compared with other Clean Power Plan compliance alternatives, and is thus worthy of inclusion in a state plan.

An example from the state of Alabama of regulatory accounting treatment of a utility plant may be instructive. In August 2011, Alabama Power petitioned the Alabama Public Service Commission for an authorization "related to cost impacts that could result from the implementation of new [EPA] regulations."[90] More specifically, Alabama Power sought:

> *Authorization to establish a regulatory asset on its balance sheet in which it would record the unrecovered investment cost associated with full or partial unit retirements caused by such regulations, including the unrecovered plant asset balance and the unrecovered cost associated with site removal and closure.*[91]

The Commission granted the company's request, allowing it to put in place an accounting approach designed "to benefit customers by addressing certain potential cost pressures they would otherwise face."[92] The Commission went on to explain:

> *Should environmental mandates from EPA result in the Company prematurely retiring a generating unit or partially retiring certain unit equipment in order to effectuate the transition of that unit's operational capability to a different fuel type, the Company will be able, through these authorizations, to recover the remaining investment costs, as well as expenses associated with unused fuel, materials and supplies, over the time period that would have been utilized for that unit, but for the [EPA's] mandates.*[93]

87 Lazar at 39.

88 Ibid.

89 Utilities and utility regulators cannot predict with perfect accuracy whether an EGU will be used and useful at some future data. The possibility of stranded costs is a factor in nearly every decision about whether to retrofit or retire a utility-owned EGU. The Regulatory Assistance Project has cited best practices on this topic and offered recommendations to utility regulators in two publications on environmental regulations: (1) Lazar, J. & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/4670; and (2) Farnsworth, D. (2014, January). *Further Preparing for EPA Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6989

90 Alabama PSC Docket U-5033, Order: September 7, 2011. Available at: https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=132f89da-98f5-4c6d-b218-c7a116224e1e at p. 1-2.

91 Supra footnote 90 at p. 2.

92 Ibid at p. 7.

93 Supra footnote 92.

On one hand, it is perhaps surprising that the utility was given preapproval for such a potentially large amount of costs, with no specific plan identifying specific regulations at issue and the actual or likely costs that the utility may face in order to comply. Information related to reasonably anticipated costs, the specific environmental regulations requiring these investments, and justification by the company for the compliance approaches it chose would normally be a condition for such preapproval. It would seem that regulators should have an opportunity to review the company's comprehensive analysis evaluating the value of the preapproved project under a range of possible outcomes. On the other hand, a policy like this allows a company to come forward and propose plant closures as an option that a state commission might reasonably consider for its cost-effectiveness and overall effectiveness. In this case, making a regulatory determination about cost recovery for unamortized rate-base balances for retiring coal plants could be an important and appropriate part of a plant's retirement plan and the state's compliance plans.

As with many regulatory matters in practice, there are balances to be struck. Rate trajectory over the transitional period is an important aspect, along with such issues as incremental carrying costs and key debt ratios. Given the regulatory status quo, in which companies are unlikely to draw attention to an uneconomic resource owing to concerns over disallowance, a policy like Alabama's could encourage utilities to consider plant retirements as an option for compliance with the EPA's Clean Power Plan requirements.

8. For More Information

Interested readers may wish to consult the following documents for more information on retiring aging power plants:

- Farnsworth, D. (2011). *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance*, pp. 20–38 for a more detailed discussion of integrated planning. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/919
- Farnsworth, D. (2014). *Further Preparing for EPA Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6989
- Lazar, J., & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates, Working to Ensure Affordable Compliance with Public Health and Environmental Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/4670
- US EPA. (2014, June). *Technical Support Document (TSD): Resource Adequacy and Reliability Analysis.* Office of Air and Radiation. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf
- Tierney, S. F. (2012, February 16). *Why Coal Plants Retire: Power Market Fundamentals as of 2012.* Analysis Group, Inc. p 2. Available at: http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/2012_Tierney_WhyCoalPlantsRetire.pdf
- US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units — GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents

9. Summary

Although closing an aging EGU can be a disruptive and challenging process, when weighed against various alternatives, it may provide a lower-cost solution and be worthy of inclusion in a state's plans for Clean Air Act compliance, including compliance with Clean Power Plan requirements.

There are various regulatory contexts in which states can review proposals to close power plants. There are also numerous factors that can affect decisions to keep a plant running or to retire it, including forward-looking market considerations, environmental regulatory requirements, and the ability to recover past plant-related investments.

States that consider plant closure as a compliance option will have to consider these issues, and the varying degree to which these factors support such a decision. However, states that do engage in this effort will be better prepared to evaluate a wider array of potential compliance options, and better able to strike their preferred balance between cost and other policy goals, including the most affordable and reliable compliance scenarios allowable under the EPA's Clean Power Plan.