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Feasibility of Flexible Technology Standards for Existing Coal-Fired Power Plants and Their Implications for New Technology Development

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ABSTRACT

This Article explores the feasibility of adding flexibility to mandates for existing power plants in order to foster technology innovation and reduce compliance costs and emissions.

Under new and proposed EPA rules a significant portion of the coal-fired electricity generating capacity will require multi-billion dollar investments to retrofit and comply with emissions standards on SO2, NOx, PM, mercury, toxic metals, acid gases, coal combustion residuals, and cooling water intake rules. A number of plant owners may find preferable to replace these plants with new units that run with today's low cost natural gas. Massive retrofit or replacement of the current coal-fired power generation fleet with today's solutions will harm the conditions for research and development of path-breaking fossil-fired power generation technologies. This would not be a serious problem if the current retrofit and replacement technologies were in fact a solution to the many environmental externalities posed by the coal-fired power plants that are now candidates for expensive retrofitting or retirement. But the technologies available today are far from being a solution commensurate with the climate and environmental risks that fossil-fired generation poses in the United States and the world. This Article finds that a policy with a flexible compliance payment that allows investors to delay the decision of retrofitting or replacing and hence, maintains incentives for innovation in retrofit and new plant technologies, can outperform an inflexible mandate by reducing compliance costs and improving environmental performance.

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INTRODUCTION

The U.S. electricity industry cannot go on operating without major modifications. Its impacts on the environment make it one of the worst global environmental offenders. Its carbon dioxide (CO_2) emissions rank third after China and the United States at large.[1] It contributes to ozone and fine particle ($PM_{2.5}$) pollution, is the dominant emitter of mercury, and is a significant emitter of other toxic metals (such as arsenic, chromium, and nickel) and acid gases.[2] Coal ash and other combustion residuals create one of the largest waste streams in the United States, and coal plants together with other thermoelectric plants are responsible for almost 40 percent of freshwater withdrawals in the United States.[3] If life cycle impacts are considered, the picture just gets worse.[4]

To tackle these problems, the U.S. Environmental Protection Agency (EPA), exercising authority under the Clean Air Act[5], has finalized major environmental regulations that, compounded with market forces, have the potential to dramatically change the landscape of the power-generation sector and forever displace coal as the leading fuel in the U.S. power-generation mix.[6] The proposed rules for new and existing plants aim at reducing water, soil, and air pollution and greenhouse gas (GHG) emissions.[7] For owners of coal-fired plants,

1. *See generally* Steven J. Davis et al., *Future CO_2 Emissions and Climate Change From Existing Energy Infrastructure*, 329 SCI. 1330, 1333 (2010) (overviewing the current and expected emissions from electricity generation in the United States and the world).
2. *See generally* Paul R. Epstein et al., *Full Cost Accounting for the Life Cycle of Coal*, 1219 ANNALS N.Y. ACAD. SCI. 73, 73–98 (2011); PAMELA L. SPATH ET AL., LIFE CYCLE ASSESSMENT OF COAL-FIRED POWER PRODUCTION, NAT'L RENEWABLE ENERGY LAB., at i–iv (1999).
3. EPSTEIN ET AL., *supra* note 2, at 73 (detailing the soil, water, and air emissions associated with the extraction, processing, transportation, and combustion of coal).
4. Life cycle impact refers to the total impact on the environment of the U.S. electricity industry's entire production cycle. For example, the life cycle impact of a coal-fired power plant would account for all the emissions associated with the extraction, processing, transportation, and combustion of the coal used in that plant. Epstein et al., *supra* note 2, at 73; SPATH ET AL., *supra* note 2 (comparing the life cycle impacts of the average U.S. boiler, new boilers that meet new source performance standards, and highly efficient boilers that exceed those standards).
5. CLEAN AIR ACT, 42 U.S.C. §7401 et seq. (1970), *available at* http://www.epw.senate.gov/envlaws/cleanair.pdf.
6. *See* Lincoln F. Pratson et al., *Fuel Prices, Emission Standards, and Generation Costs for Coal vs. Natural Gas Power Plants*, 47 ENVTL. SCI. & TECH. 4926, 4926–33 (2013) (describing how a combination of EPA rules and relatively lower natural gas prices changes the respective marginal costs of coal and gas electricity generation).
7. *See Cooling Water Intake Structures—CWA §316(b)*, U.S. ENVTL. PROT. AGENCY, http://water.epa.gov/lawsregs/lawsguidance/cwa/316b (last visited Mar. 3, 2014) (describing the proposed rule for cooling water systems for existing power plants); *Hazardous and Solid Waste Management System: Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities*, U.S. ENVTL. PROT. AGENCY, http://www.regulations.

compliance would require multimillion-dollar investments.[8] This poses a significant challenge for investors, given uncertainty about future growth of electricity demand and future regulatory constraints on GHG emissions. Instead of being retrofitted, plants may be replaced with new coal-fired power plants or, more likely, with gas-fired power plants.[9] In fact, a number of recent studies predict that between three and eighty-five gigawatts (GWs) of coal-fired capacity will be retired before 2020 because of the compounded effects of EPA rules, low natural gas prices, uncertain electricity demand growth, and potential limits on GHG emissions from existing sources.[10]

But the simultaneous replacement of significant amounts of generation capacity from coal-fired power plants with natural gas-fired units will require the development of massive infrastructure to extract, transport and store natural gas (and to export coal).[11] Consequently, if the decision to switch from coal to gas turns out to have been ill-advised, reversing it will be exceedingly expensive (if not impossible), at least in the short term.[12]

Another potential consequence of massive simultaneous investment that either replaces or retrofits coal plants is that after such transformation has occurred, the demand for new fossil-fired power plants may be dramatically reduced.[13] Un-

gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-0352 (last visited Mar. 3, 2014) (describing proposed rules affecting coal ash management systems for existing coal-fired power plants); *Mercury and Air Toxics Standards (MATS)*, U.S. ENVTL. PROT. AGENCY, http://www.epa.gov/mats/ powerplants.html (last visited Mar. 3, 2014) (describing proposed air emission rules for existing power plants); *What EPA is Doing*, U.S. ENVTL. PROT. AGENCY, http://www2.epa.gov/carbon-pollution-standards/what-epa-doing (last visited Mar. 3, 2014) (describing proposed rules for regulating CO_2 emissions from new and existing power plants).

8. *See generally* DAVID FARNSWORTH, REGULATORY ASSISTANCE PROJECT, PREPARING FOR EPA REGULATIONS: WORKING TO ENSURE RELIABLE AND AFFORDABLE ENVIRONMENTAL COMPLIANCE (2011).

9. Dalia Patiño-Echeverri et al., *Should a Coal-Fired Power Plant Be Replaced or Retrofitted?*, 41 ENVTL. SCI. & TECH. 7980, 7980–86 (2007) (discussing the compliance alternatives for air emissions rules for coal-fired power plants).

10. Blair Beasley et al., *Mercury and Air Toxics Standards Analysis Deconstructed: Changing Assumptions, Changing Results* 19 (Res. for the Future, Discussion Paper No. 13-10, 2013), *available at* http://ssrn.com/abstract=2251261 (reviewing a number of recent studies on the impact of the EPA's MATS rule on the electricity-generation sector).

11. *See* Cong Liu et al., *Coordinated Scheduling of Electricity and Natural Gas Infrastructures With a Transient Model for Natural Gas Flow*, 21 CHAOS 025102-1, 025102-1 (discussing the interdependency of power and natural gas infrastructures).

12. INGAA FOUND. & ICF INT'L, NATURAL GAS PIPELINE AND STORAGE INFRASTRUCTURE PROJECTIONS THROUGH 2030, 4 (2009) (projecting a range of investment from $133 to $210 billion in infrastructure over the next twenty years to meet increased natural gas demand from the electricity-generation and industrial sectors).

13. *AEO2014 Early Release Overview*, U.S. ENERGY INFO. ADMIN. (Dec. 16, 2013), http://www.eia.gov/forecasts/aeo/er/early_elecgen.cfm (follow "Interactive Table Viewer" hyperlink; Subject Filter: Electric Power Sector; Table: Electricity Generation Capacity; Region: No Regional Tables;

less there are abrupt changes in the U.S. technological and economic landscape—massive electrification of the transportation system or increased industrial production growth spurred by low natural gas prices, for example—electricity demand will remain constant or will grow by less than 1 percent.[14] Thus, for at least the expected lifetime of the new replacement plants, there will be only a small need for new fossil-fired plants. If plants are retrofitted rather than replaced, these retrofits would be made with the intention of continuing plant operation for two decades or more, which would also have the effect of reducing the size of the market for new plants.[15]

Some pathbreaking electricity-generation technologies may become commercially available in the near future if there is the expectation that a sizable and profitable market for them exists. And if this is so, then replacing a large percentage of the electricity-generation capacity of the United States with the technology that is commercially available today may have two bad outcomes. First, it may discourage and reduce the Research, Development and Demonstration (RD&D) expenditures of firms in search of game-changing technologies for fossil-fired electricity generation. Second, even if firms continue investing and the pathbreaking technologies materialize, there may not be space for them in the marketplace. This would not be a serious problem if the current retrofit and replacement technologies were in fact a solution to the many environmental externalities posed by the coal-fired power plants that are now candidates for expensive retrofitting or retirement. But the technologies available today are far from being a solution commensurate with the climate and environmental risks that fossil-fired generation poses. Current retrofit technologies for reducing emissions of conventional pollutants from coal-fired power plants have high capital costs and significant energy penalties that result in less electricity generation for the same fuel consumption.[16] Similarly, replacing coal-fired power plants with natural gas units may reduce GHG emissions from the combustion phase

select "Reference Case"; Row "Cumulative Planned Additions 9/") (projecting coal-fired cumulative capacity additions of only 2.2 GWs throughout the outlook, which corresponds to no more than two large coal-fired power plants).

14. *Id.* (projecting electricity demand growing at an average annual rate of 0.9 percent, and stating that "the combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of environmental rules dampens future coal use").

15. *See generally* Dalia Patiño-Echeverri et al., *Economic and Environmental Costs of Regulatory Uncertainty for Coal-Fired Power Plants*, 43 ENVTL. SCI. & TECH. 578, 578–84 (2009) (discussing how large capital costs and long economic lives of retrofitted plants cause investors to plan over a long horizon).

16. *See id.* at 580 tbl.1 (reporting the annual energy consumption of different emissions control technology for a coal-fired power plant).

by half, but it is uncertain whether life-cycle GHG emissions are reduced.[17] Finally, even if we were certain of the environmental superiority of natural gas, there are several regions in the world where the scarcity and high cost of this resource point to coal as the most affordable solution to meet their needs for massive base-load power generation (for example, Japan after the closure of nuclear plants[18] or developing nations with large underserved populations[19]). For many of the coal-dependent developing nations, any policy that reduces the chances that breakthrough coal and gas technologies come to market in the short term directly harms their prospects for development.[20] Hence, for a number of reasons, reaching ambitious GHG emissions–abatement goals requires more than just fuel switching from coal to gas, and there is value in keeping a good environment for the development of pathbreaking fossil-fired power-generation technologies.

So, proceeding under the assumption that pathbreaking technologies for fossil-fired electricity generation are under development but not commercially ready for installation today, and that efforts on this RD&D activity would be greatly reduced if there is massive retirement of coal plants in the United States, this Article argues that postponing the retirement or retrofitting of some coal-fired power plants would have economic and environmental benefits. Since postponement of investment for some plants would be beneficial, this Article explores whether and how policy makers can design mechanisms that motivate optimal replacement timing (that is, investment timing that accomplishes the same environmental protection objectives at a reduced cost). One such policy mecha-

17. Given that methane is a potent greenhouse gas (with a global warming potential equivalent to twenty-five times the warming potential of CO_2 on a hundred-year horizon and seventy-two times the warming potential of CO_2 on a twenty-year horizon), methane emissions during natural gas production and transmission have the potential to outweigh the environmental benefits derived from lower CO_2 emissions from combustion in natural gas power plants compared to emissions from coal plants. A recent study suggests that methane emissions due to fossil fuel extraction and processing could be 4.9 +/- 2.6 times larger than in EDGAR, the most comprehensive global methane inventory. Scot M. Miller et. al., *Anthropogenic Emissions of Methane in the United States*, PNAS EARLY EDITION, Oct. 18, 2003, at 1, 5, *available at* http://www.pnas.org/cgi/doi/10.1073/pnas.1314392110.

18. *See generally* Osamu Tsukimori & Aaron Sheldrick, *Japan's Soaring Coal Use May Push Down LNG Imports This Year*, REUTERS (Nov. 28, 2013, 3:59 PM), http://www.reuters.com/article/ 2013/11/28/japan-power-outlook-idUSL4N0JB1AA20131128 (explaining that Japan was burning a high amount of coal as it tried to lower the cost of replacing nuclear energy).

19. *See generally* SCOTT MORRIS & BILLY PIZER, CTR. GLOBAL DEV., THINKING THROUGH WHEN THE WORLD BANK SHOULD FUND COAL PROJECTS 5, 13–14 (2013) (arguing that in poor countries with limited access to hydroelectric and geothermal sources, coal may be the only alternative for obtaining reliable electricity, and hence that the World Bank should be ambitious in working toward clean energy approaches in its development strategies but should not rule out coal in all circumstances).

20. *Id.* at 13.

nism is a flexible technology standard that would provide plant owners with the option to make an alternative compliance payment (FlexACP). This Article finds that under certain conditions, it is possible to create a FlexACP policy that can outperform a traditional mandate by both reducing cumulative emissions and improving economic efficiency.

This Article is organized in three Parts. Part I reviews the concept of flexibility for environmental regulations and discusses the opportunities for flexible regulatory mechanisms under the Clean Air Act.[21] Part II describes the investment decision problem facing the owner of an existing coal-fired power plant and the challenges of selecting a compliance strategy under uncertainty about fuel prices, future regulations, and technological advancement. Part III proposes a framework for determining whether flexible technology policy can outperform a traditional performance standard, concluding that given available information on current retrofit and replacement plant technologies and an example of a potentially path-breaking technology, it is indeed possible to design an economically efficient FlexACP that reduces SO_2, NOx, and CO_2 cumulative emissions.

I. THE FEASIBILITY OF FLEXIBLE PERFORMANCE STANDARDS UNDER THE CLEAN AIR ACT

A. Current and Expected Rules Affecting Existing Coal-Fired Power Plants

Two major pieces of EPA rulemaking announced in 2011—the Cross-State Air Pollution Rule (CSAPR)[22] and the Mercury and Air Toxics Standards (MATS)[23]—and the prospects of a near-term promulgation of a third rule limiting CO_2 emissions from existing sources (as required by the Clean Air Act (CAA) section 111(d)[24] GHG rule) are at least partially responsible for the announcement of massive retirement of coal-fired generation.[25] The estimated

21. CLEAN AIR ACT, *supra* note 5.
22. Cross-State Air Pollution Rule (CSAPRP) U.S. ENVTL. PROT. AGENCY, http://www.epa.gov/airtransport/CSAPR (last visited June. 22, 2014).
23. *Mercury and Air Toxics Standards (MATS)*, *supra* note 7.
24. CAA § 111(d) requires states to develop plans for existing sources of noncriteria pollutants (i.e., a pollutant for which there is no national ambient air quality standard) whenever EPA promulgates a standard for a new source. CLEAN AIR ACT, *supra* note 5, § 111(d). These are called Section 111(d) plans and are subject to EPA review and approval. *See also Section 111(d) Plans*, U.S. ENVTL. PROT. AGENCY, http://www.epa.gov/region07/air/rules/111d.htm (last visited Mar. 3, 2014).
25. The Energy Information Administration reported that twenty-seven gigawatts (GWs) of capacity (representing 8.5 percent of total U.S. generating capacity in 2011) from 175 coal-fired power generators would be retired between 2012 and 2016. *27 Gigawatts of Coal-Fired Capacity to Retire Over Next Five Years*, U.S. ENERGY INFO. ADMIN. (July 27, 2012), http://www.eia.gov/today

high compliance costs of these rules compounded with the low natural gas prices seen in recent years made the economic case for retiring older and less efficient coal-fired units.[26] While the CSAPR has just been upheld after more than twenty months of litigation,[27] the MATS have been in force since 2011 with compliance required by 2015, with possible extensions.[28]

The CSAPR, finalized in July 2011, seeks to significantly reduce sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions from existing power plants in twenty-eight states that, by emitting pollutants that cross state lines, make it difficult for downwind states to meet the ozone and fine particle National Ambient Air Quality Standards (NAAQS).[29] In August 2012, the U.S. Court of Appeals for the District of Columbia Circuit overturned the rule.[30] The EPA contended that the Circuit Court exceeded its jurisdiction when it vacated the CSAPR and in March of 2013, petitioned the U.S. Supreme Court to review the Circuit Court's decision. On April 29, 2014, the Court upheld CSAPR.[31] The CSAPR sets SO_2 and NOx annual and ozone emissions budgets for states based on contributions to downwind NAAQS noncompliance, with budgets increasing in stringency for selected states over time. Regulated electricity generating units can comply with the rule through unlimited intrastate trading and limited interstate trading as well as pollution control options to reduce on site emissions.[32]

The MATS, effective December 2011, reduces emissions of heavy metals, including mercury, arsenic, chromium, and nickel, as well as acid gases, including hydrochloric acid and hydrofluoric acid, from new and existing oil and coal-fired power plants by setting emissions limits for individual units. The reduction of these hazardous pollutants would also reduce SO_2 (an acid gas) and fine particle ($PM_{2.5}$) emissions. The rule has some degree of flexibility and allows sources to comply by averaging across multiple units.[33]

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inenergy/detail.cfm?id=7290. These retirements would be higher than the previous five-year period and would be due at least in part to the high compliance costs of EPA rules. *Id.*

26. *See, e.g.*, Beasley et al., *supra* note 10, at 27–28 (reviewing a number of recent studies on the impact of the EPA's MATS rule on the electricity-generation sector).
27. *See* Brief for Petitioner, United States Envtl. Prot. Agency v. EME Homer City Generation, 696 F.3d 7 (2013) (Nos. 12-1182 & 12-1183) [hereinafter Brief for Petitioner].
28. *See Mercury and Air Toxics Standards (MATS)*, *supra* note 7.
29. Clean Air Act *supra* note 5, 40 CFR part 50; *see also* Envtl. Prot. Agency Clean Air Transport Rule, docket number EPA-HQ-OAR-2009-0491.
30. EME Homer City Generation v. Envtl. Prot. Agency, No. 11-1302 (D.C. Cir. 2012).
31. *See generally* Brief for Petitioner, *supra* note 27; Envtl. Prot. Agency v. EME Homer City Generation, No. 12-1182, slip op. (U.S. 2013).
32. Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals; Final Rule. EPA 40 CFR Parts 50, 51, 72 et al. http://www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf (last visited June 20, 2014).
33. For a description of MATS and its flexibility, see Beasley et al., *supra* note 10.

To comply with MATS acid gas requirements and CSAPR annual SO_2 emissions budgets, nonretiring coal units without existing acid gas controls are projected to install wet and dry flue gas desulfurization controls or dry sorbent injection. Many coal units can comply with these regulations using existing acid gas controls, and some coal units are projected to comply by burning low acid gas coal.[34] Compliance with MATS mercury and other toxic metal requirements is achieved through particulate control technology such as a fabric filter in combination with activated carbon injection. Coal units with select catalytic reduction and wet flue gas desulfurization also control mercury emissions. CSAPR annual and seasonal NOx emissions caps are projected to be met through selective catalytic and noncatalytic reduction controls on some units.[35]

Besides the CSAPR (or the CSAPR's replacement) and the MATS, another regulatory factor that has affected, and will continue to affect, capital investment decisions in existing coal-fired power plants is the prospect for a new rule that would constrain CO_2 emissions. In September 2013, the EPA proposed a CO_2 emissions standard for new power plants of 1100 pounds per megawatt-hour (lbs/MWh) for coal and small gas plants, and of 1000 lbs/MWh for large gas units over a twelve month operating period. For coal plants, it is also possible to comply by achieving a CO_2 emissions rate of 1000-1050 lbs/MWh over an eighty-four month (seven year) operating period. Coal-fired power plants have a much higher compliance cost than natural gas plants since they can only meet the standard by installing carbon capture and sequestration equipment.[36] Because of this rule, no new coal-fired power plants are proposed in the short term.[37] Under the Clean Air Act section 111(d), once the EPA formulates the rules for new plants, it has to do so for existing plants.[38] Given that the new

34. National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 40 C.F.R. pts. 60, 63, *available at* http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf (last visited June 20, 2014); Jennifer Macedonia & Colleen Kelly, *BPC Modeling Results: Projected Impact of Changing Conditions on the Power Sector*, BIPARTISAN POLICY CENTER (July 19, 2012), http://bipartisanpolicy.org/library/report/bpc-modeling-results-projected-impact-changing-conditions-power-sector.

35. JENNIFER MACEDONIA ET. AL, BIPARTISAN POLICY CENTER, ENVIRONMENTAL REGULATION AND ELECTRIC SYSTEM RELIABILITY (2011).

36. *See generally* JAMES E. MCCARTHY, CONG. RESEARCH SERV., R43127, EPA STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM POWER PLANTS: MANY QUESTIONS, SOME ANSWERS 5–6 (2013) (discussing the new proposal).

37. *Id.*

38. *See Section 111(d) Plans*, supra note 24 ("Section 111(d) of the [Clean Air] Act requires states to develop plans for *existing* sources of noncriteria pollutants (i.e., a pollutant for which there is no national ambient air quality standard) whenever EPA promulgates a standard for a new source.").

rules are finalized, the EPA needed to propose a standard for existing sources by June 2014 and issue the final rule by June 2015. Following this requirement on June 18 EPA issued a notice of proposed rulemaking with guidelines for states to reduce carbon emission pollution from electric utility generating units.[39] States will be required to submit an implementation plan by June 30, 2016, consistent with the schedule laid out by President Obama's climate plan which uses executive authority to reduce GHG emissions by 17 percent in 2020 compared to 2005 levels.[40]

B. Possibilities for Flexible Compliance Under the Clean Air Act

Innovation is affected by three attributes of regulation: stringency, certainty, and flexibility.[41] Stringency refers to the ambitions of the regulation and the burden of compliance imposed on firms.[42] In general, more stringent regulations imply higher costs of compliance. Certainty refers to the degree to which firms know what to expect from current and future regulations, in terms of stringency, flexibility, and timing. Flexibility refers to the number of compliance alternatives available to the regulated entity.[43] For the same level of stringency, a flexible regulation has the potential to reduce the compliance burden on firms and may also foster technological innovation.[44]

Of the three attributes of regulation, flexibility is perhaps the one that policy makers can manipulate the most to achieve desirable outcomes. The effect that one rule can have on regulatory uncertainty may or may not be under the policymaker's control. Also, it may be hard to change the stringency of a rule without compromising environmental goals. In contrast, policymakers can increase or decrease the flexibility of a rule without necessarily compromising environmental protection objectives.[45]

39. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 117 (proposed June 18, 2014).
40. For a description of the President's goals regarding carbon emissions for the power sector see EXEC. OFFICE OF THE PRESIDENT, THE PRESIDENT'S CLIMATE ACTION PLAN (June 2013), *available at* http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.
41. Luke A. Stewart, The Impact of Regulation on Innovation in the United States: A Cross-Industry Literature Review 3 (June 2010) (unpublished paper), *available at* http://www.itif.org/publications/impact-regulation-innovation-united-states-cross-industry-literature-review.
42. *Id.*
43. *Id.*
44. *Id.*; *see also* Dallas Burtraw & Matt Woerman, *Technology Flexibility and Stringency for Greenhouse Gas Regulations* 24 (Res. for the Future, Discussion Paper No. 13-24, 2013) (analyzing the relationship between flexibility and stringency).
45. Stewart, *supra* note 41.

The traditional inflexible approaches used to reduce air emissions from new and existing sources include performance standards based on what is technologically feasible. Some standards for new sources set performance targets based on the best available technology, and others on maximum achievable controls technology, while standards for existing sources may be based on reasonably available controls technology.[46] The economics literature contrasts these technology-based approaches with more flexible incentive-based approaches.[47] One example of a flexible approach is a cap and trade mechanism that allows units to comply either by meeting or exceeding an emissions target, or by buying emissions rights from firms that overcomply.[48] Another example of a flexible approach is the imposition of a tax on units of emissions.[49] When comparing traditional technology-based approaches with flexible price-based ones, both economic theory and empirical analysis find the latter more likely to result in the achievement of emissions targets, reduce compliance costs,[50] and promote technological innovation by providing incentives to reduce emissions beyond what is required.[51]

At a first glance, the three pieces of regulation constraining the investment and operations of existing power plants have a low degree of flexibility.[52] However, the Clean Air Act does allow for some degree of flexibility. A number of programs under the Clean Air Act use market-based incentive approaches to

46. *See* Summary of the Clean Air Act, U.S. ENVTL. PROT. AGENCY, http://www2.epa.gov/ laws-regulations/summary-clean-air-act (last visited Mar. 3, 2014) (stating that the Clean Air Act Amendment revision of § 112, which addressed emissions of hazardous air pollutants, requires the EPA to issue technology-based standards commonly referred to as "maximum achievable control technology" or "MACT" standards).

47. *See* WILLIAM J. BAUMOL & WALLACE E. OATES, THE THEORY OF ENVIRONMENTAL POLICY 57–78 (2d ed. 1988).

48. *See id.* (discussing the advantages of tradable emission permits when abatement costs and benefits are uncertain); Steffen Brunner et al., *Emissions Trading Systems: An Overview* (Potsdam Inst. for Climate Impact Research, Discussion Paper) (reviewing different designs of cap and trade systems).

49. *See* Richard G. Newell & William A. Pizer, *Regulating Stock Externalities Under Uncertainty*, 45 J. ENVTL. ECON. & MGMT. 416, 418–19 (2003) (comparing cap and trade programs with taxes as policy mechanisms to reduce greenhouse gas emissions).

50. *See* Joshua Linn et al., *Regulating Greenhouse Gases from Coal Power Plants Under the Clean Air Act* 2 (Res. for the Future, Discussion Paper No. 13-05, 2013).

51. *See generally* Paul B. Downing & Lawrence J. White, *Innovation in Pollution Control*, 13 J. ENVTL. ECON. & MGMT. 18 (1986) (providing a model of pollution control innovation); Wesley A. Magat, *Pollution Control and Technological Advance: A Dynamic Model of the Firm*, 5 J. ENVTL. ECON. & MGMT. 1 (1978) (comparing taxes and standards and showing that these two pollution control policies lead to a distinctly different allocation of research and development funds between improvement in abatement technology and improvement in production technology); Scott R. Milliman & Raymond Prince, *Firm Incentives to Promote Technological Change in Pollution Control*, 17 J. ENVTL. ECON. & MGMT. 247 (1989) (discussing five regulatory regimes and how they create incentives to promote technological change).

52. Summary of the Clean Air Act, *supra* note 46.

achieve emissions reductions goals. The Acid Rain Program is perhaps the best example of a successful flexible policy mechanism that is far superior to a command-and-control approach.[53] The cap and trade mechanism of the Acid Rain Program allows sources to comply with whatever strategy is most economical. Plants may switch fuels, install scrubbers, or trade emissions allowances to comply.[54] As a result, during the last two decades the electricity industry has seen a reduction in SO_2 and NOx emissions at a cost that is estimated to be about three billion dollars per year lower (50 percent less) than the cost of a traditional command-and-control rule.[55] The Acid Rain Program is also credited for spurring technological improvements and cost reductions on emissions control equipment for coal-fired power plants.[56] The fact that trading reduces compliance costs when firms have heterogeneous marginal costs of compliance is well supported by historical evidence and by economic theory.[57]

In contrast, two other mechanisms of the Clean Air Act—new source performance standards (NSPS)[58] and new source review (NSR)[59] requirements—may have hindered innovation in emissions control technologies. By increasing the capital costs of new plants, NSPS may have created incentives for keeping old coal plants operating beyond their economic life.[60] Similarly, NSR may have stifled innovation by creating disincentives to adopt innovative technologies because

53. *See generally* Robert N. Stavins, *What Can We Learn from the Grand Policy Experiment? Lessons from SO_2 Allowance Trading*, 12 J. ECON. PERSP. 69, 70–71 (1998) (discussing added benefits of Acid Rain program).

54. *See* A. Denny Ellerman & Juan Pablo Montero, *Why Are Allowance Prices So Low? An Analysis of the SO_2 Emissions Trading Program* 1, 6, 9 (MIT Ctr. for Energy & Envtl. Policy Research, Working Paper No. 96-001, 1996).

55. *See Clean Air Markets, Acid Rain Program*, ENVTL. PROT. AGENCY, http://www.epa.gov/airmarkt/progsregs/arp/basic.html#model (last updated July 25, 2012) (discussing the sulfur dioxide and nitrogen oxide reductions).

56. David Popp, *Pollution Control Innovations and the Clean Air Act of 1990*, 22 J. POL'Y ANALYSIS & MGMT. 641, 658–59 (2003).

57. Stephen P. Holland et al., *Greenhouse Gas Reductions Under Low Carbon Fuel Standards?*, 1 AM. ECON. J.: ECON. POL'Y 106. 120 (2009).

58. NSPS § 111 of the Clean Air Act authorized the EPA to develop technology based standards which apply to specific categories of stationary sources. These standards are referred to as New Source Performance Standards (NSPS) and are found in *40 CFR Part 60*. The NSPS apply to new, modified and reconstructed affected facilities in specific source categories such as manufacturers of glass, cement, rubber tires and wool fiberglass. As of 2005, there were approximately 75 NSPS.

59. NSR: New Source Review is a Clean Air Act requirement to adopt state-of-the-art pollution controls when a stationary source undergoes major modifications.

60. Garth Heutel, *Plant Vintages, Grandfathering, and Environmental Policy*, 61 J. ENVTL. ECON. MGMT. 1, 36–51. (showing that more stringent performance standards for new sources decreased investment in new boilers.); James B. Bushnell & Catherine Wolfram, *Enforcement of Vintage Differentiated Regulations: The Case of New Source Review*, 64 J. ENVTL. ECON. MGMT. 2, 137–52 (showing a reduction in investment in existing plants after heightened enforcement of NSR).

of concerns that they may trigger the requirement to adopt state-of-the-art pollution control.[61]

In recent years, the EPA has issued and proposed command-and-control mandates for existing sources that can be best classified as technology-based standards because they effectively require investment in a particular technology and hence have little compliance flexibility.[62] But the CAA does not preclude the introduction of flexibility. On the contrary, as argued by Jody Foster and Rob Brenner, the CAA promotes flexibility as a way to achieve environmental goals more efficiently.[63] Foster and Brenner identify flexible regulatory mechanisms available under the CAA that could accelerate the deployment of clean air and clean energy technologies.[64] The first mechanism they identify is the State Implementation Programs (SIPs).[65] They find that the CAA gives states great discretion in developing compliance strategies for SIPs.[66] They argue that this discretion may permit the state to adopt innovative and alternative compliance options. As an example, they point out the possibility that the state authority under section 111(d) to address GHG emissions from existing sources includes the authority to develop trading programs and other measures that may foster technological innovation to aid reaching the program's goals.

Another mechanism identified in the Foster and Brenner report is section 111(j) on Innovative Control Technology Waivers, which provides compliance flexibility for sources seeking to deploy innovative technologies.[67] This provision of the CAA provides extra compliance time for sources using new "first-of-a-kind" technologies and allows the EPA to delay the application of new source performance standards (NSPSs) to these sources.[68] The provision gives sources up to seven years after the waiver is granted or up to four years after the plant starts operating, whichever is earlier, to demonstrate the viability of the technology.[69] If the technology fails to reach viability, the EPA may grant the source up to

61. *See* Howard K. Gruenspecht & Robert N. Stavins, *New Source Review Under the Clean Air Act: Ripe for Reform*, 147 RESOURCES 19, 22 (2002) (arguing that the new source review program wastes resources and can retard environmental progress); Dalia Patiño-Echeverri et al., *Flexible Mandates for Investment in New Technology*, 44 J. REG. ECON. 121, 145 (2013) (showing that new source performance standards for CO_2 are likely to delay investment in new power plants).
62. Summary of the Clean Air Act, *supra* note 46.
63. JODY FOSTER & ROB BRENNER, NICHOLAS INST. FOR ENVTL. POLICY SOLUTIONS, CLEAN AIR AND TECHNOLOGY INNOVATION: WORKING CONCEPTS FOR PROMOTING CLEAN TECHNOLOGY INNOVATION UNDER THE CLEAN AIR ACT (2013).
64. *Id.*
65. *See* CLEAN AIR ACT, *supra* note 5, §§ 107, 110, 113 (referring to state implementation plans SIPs).
66. *Id.*
67. CLEAN AIR ACT, *supra* note 5, § 111(j)(1)(A).
68. *See* Foster and Brenner, *supra* note 63; CLEAN AIR ACT, *supra* note 5, § 111(j)(1).
69. *See* Foster and Brenner, *supra* note 63; CLEAN AIR ACT, *supra* note 5, § 111(j)(2).

three years to comply with the regular NSPSs.[70] The EPA has used its regulatory authority to make this waiver applicable to the requirement of installing a Best Achievable Control Technology (BACT) stated by the Prevention of Significant Deterioration (PSD).[71]

A third mechanism is the Supplemental Environmental Projects (SEPs) that are part of settlement agreements that resolve federal actions against companies in violation of environmental laws.[72] As part of a settlement, alleged violators may agree to undertake an environmentally beneficial project related to the violation in exchange for mitigation of the fine to be paid. Using this mechanism the EPA may persuade sources to invest in innovative projects in lieu of fines.[73]

Although it may be challenging to design flexible standards for existing coal-fired plants, these three mechanisms for introducing flexibility indicate that it is possible to depart from inflexible standards. Indeed, Dallas Burtraw et al. propose a tradable performance standard for CO_2 that would set a uniform emissions rate and allow generators that exceed the standard to generate and sell credits to generators that do not meet the standard.[74] In order to identify the design attributes of an effective flexible mandate, it is necessary to thoroughly understand the tradeoffs associated with the various compliance alternatives open to owners of coal plants. The next Part seeks to describe these tradeoffs in detail.

II. THE DECISIONMAKING PROBLEM FACED BY OWNERS OF OLD AND DIRTY COAL-FIRED POWER PLANTS AND THE VALUE OF THE OPTION TO POSTPONE INVESTMENT

To the question "what to do with this plant?" there are at most four answers: retrofitting, replacing, mothballing, or continuing operation of the plant

70. *See* Foster and Brenner, *supra* note 63; CLEAN AIR ACT, *supra* note 5, § 111(j)(2).
71. *Prevention of Significant Deterioration (PSD) Basic Information*, U.S. ENVTL. PROT. AGENCY, http://www.epa.gov/NSR/psd.html (last visited June 22, 2014).
72. Memorandum from Steven A. Herman, Assistant Administrator of the Office of Enforcement and Compliance Assurance, U.S. Envtl. Prot. Agency, to Regional Administrators of the Office of Enforcement and Compliance Assurance, U.S. Envtl. Prot. Agency (Apr. 10, 1998), *available at* http://www2.epa.gov/enforcement/supplemental-environmental-projects-seps.
73. EPA has proposed states use SEPs to promote energy efficiency and renewable energy. *See* Memorandum from Brian McLean, Director of the Office of Atmospheric Programs, U.S. Envtl. Prot. Agency and Walker Smith, Director of Office Regulatory Enforcement and Office of Enforcement and Compliance Assurance, U.S. Envtl. Prot. Agency, to Regional Air Division Directors, U.S. Envtl. Prot. Agency, (Jan. 27, 2005), *available at* http://www.epa.gov/statelocalclimate/documents/pdf/sep_toolkit.pdf.
74. *See* Dallas Burtraw et al., *The Costs and Consequences of Clean Air Act Regulation of CO_2 From Power Plants,* 2 (Res. for the Future, Discussion Paper No. 14-01, 2014) (comparing the outcomes of tradable performance standards and cap and trade approaches).

without modifications (in other words, waiting to make a decision).[75] The last two alternatives—mothballing and operating an unmodified plant—may not be available depending on plant characteristics and environmental rules. The decision is a hard one, as it needs to be made under uncertainty about key variables affecting the profitability of any alternative, such as future fuel prices, costs and performance of future technologies, future regulations, and other factors.

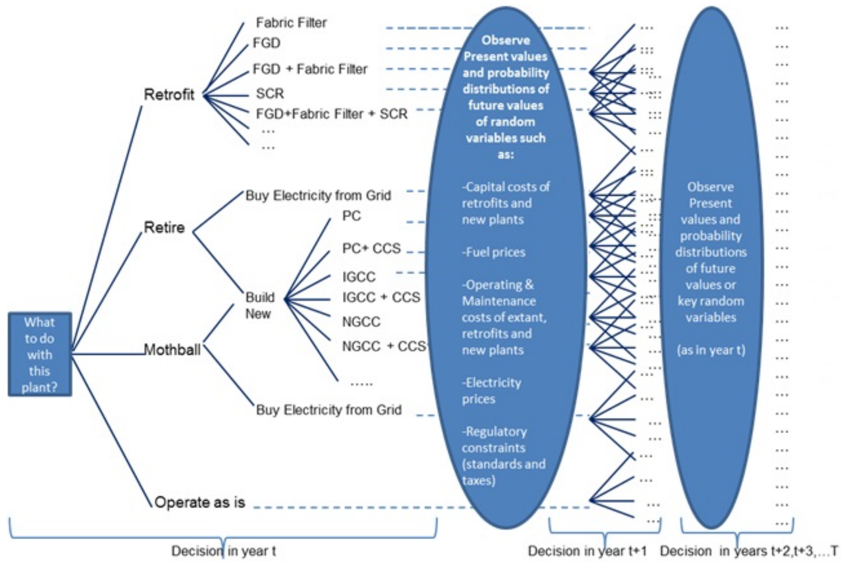
The decision tree depicted in Figure 1 illustrates the alternatives available at the first period of the decision and the subsequent alternatives available thereafter. Possible retrofit alternatives include fabric filters, flue gas desulfurization systems (FGDs), selective catalytic reduction (SCR), carbon injection (CI), and carbon capture and storage (CCS) equipment. Options for new plants include pulverized coal (PC) plants, PC plants with CCS equipment, integrated coal gasification combined cycle (IGCC) plants, IGCC plants with CCS equipment, natural gas combined cycle (NGCC) plants, and NGCC plants with CCS equipment. The option to wait may not exist at all for two reasons. First, the lead time required for installing retrofits or new plants may require making such decisions immediately in order to meet the tight compliance deadlines. (For example, to comply with MATS, coal-fired power plants must have SO_2 scrubbers by 2016, but it may take more than two years to install such equipment). Second, a rule like MATS does not differentiate between plants that are operational or mothballed, and so mothballing a plant without bringing it to compliance is not an option. Only plants that have to operate to ensure power grid reliability can be granted an extension in the deadline for compliance until 2017.[76] And depending on the plant's characteristics, some retrofit alternatives may not be available if they are inadequate to bring the plant into compliance with environmental rules. (For example, a fabric filter alone would probably not meet the MATS requirements). Finally, the alternatives of installing conventional PC plants or IGCC power plants without CCS technology may be off the table, given that under the EPA's proposal, new coal-fired units would need to meet a CO_2 emissions limit of 1100 lbs/MWh over a twelve month operating period, or 1000-1050 lbs/MWh over an eighty-four month (seven year) operating period, which cannot be achieved without at least beginning the installation of CCS technology as soon as the plant starts operation.[77]

75. *See* Patiño-Echeverri, *supra* note 9.

76. Memoradum from Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance, U.S. Envtl. Prot. Agency, to Regional Administrators, Regional Counsel, Regional Enforcement Division Directors, and Air Division Directors, U.S. Envtl. Prot. Agency (Dec. 16, 2011), *available at* http://www2.epa.gov/sites/prodution/files/documents/mats-erp.pdf.

77. The EPA's proposal gives coal units some compliance flexibility by allowing them to average emissions over multiple years. This would allow plants to operate without CCS for some initial

FIGURE 1. **Decision Tree for the Investment Decision Facing Owners of a Coal-Fired Plant**[78]



A. Retrofitting or Replacing and Choosing Between Coal and Gas

The costs of compliance with new and proposed EPA rules depend on the characteristics of the coal plant and the state's implementation of such rules. In many cases, compliance requires substantial retrofits even if the plants already have environmental controls. For example, in its proposal to bring the Mills Creek plant into compliance with the CSAPR, the MATS, and the SO_2 NAAQS rules, Louisville Gas and Electric got approval from the Kentucky Public Service Commission for retrofit plans with an estimated total cost of $1268

years but would probably not allow for postponing the decision of investing in CCS given the construction lead time of this technology. *See generally* MCCARTHY, *supra* note 37 (discussing the proposal).

78. The tree denotes the decisions that need to be made at each point in time and the uncertainties that are considered. When making the decision in the first period, investors will consider the present value and probability distributions of all those variables affecting the outcome of each investment alternative (listed inside the blue ovals). Decision alternatives that have been crossed out are those that may not be available depending on the plant and the state.

million[79] (which averages out to 856 dollars per megawatt of net capacity (\$/MW)).[80]

The decision to retrofit or replace is not an easy one and inevitably requires making assumptions about future fuel prices, emissions regulations, and the economic lifetime of the retrofitted plant.[81] Retrofitting an old coal-fired power plant may be the least costly alternative under a scenario that assumes three conditions: (1) low coal prices relative to natural gas prices, (2) no future CO_2 emissions constraints for existing sources, and (3) usage of the retrofitted plant for the next two decades. However, it may be the most expensive option under other scenarios, such as those with very low natural gas prices, moderate policies to control GHG emissions (such as moderate taxes), or early retirement of the retrofitted plant.

The example of a decisionmaker who is only concerned with uncertain fuel gas prices but does not regard those scenarios that increase constraints on GHG emissions from existing or new coal plants as plausible illustrates the difficulty of the decision whether to retrofit or replace.[82] In this case, the decisionmaker is only concerned about the risks of choosing a technology that ends up having expensive fuel costs. Fuel cost is determined by the plant's efficiency and the price of fuel. While new and retrofitted coal- and natural gas–fired power plants have almost-constant generating efficiencies (of 38 percent and 50 percent respectively), the prices of both fuels are expected to vary with time.[83] The natural-gas-to-coal fuel price ratio (NG2CP) provides a useful way to compare the cost of electricity between coal- and gas-fired plants. In the last decade the NG2CP has varied between 1 and 5 with an average value of 3.5.[84] Recently the

79. Louisville Gas and Electric (LG&E) submitted these plans early—in anticipation of the regulations—and was one of the first utilities in the nation to do so. The plans called for installing fabric filters (baghouse), activated carbon injection, and lime injection for sulfuric acid mist at the four generating units, improving the selective catalytic reduction equipment at units three and four, and installing new or upgraded flue gas desulfurization systems serving all units. *See generally* David Hoppock et al., *Determining the Least-Cost Investment for an Existing Coal Plant to Comply With EPA Regulations Under Uncertainty* (Nicholas Inst. for Envtl. Policy Solutions, Working Paper 12-03, 2012) (discussing the LG&E case). The estimated total cost of retrofitting Mill Creek to comply with CSAPR and MATS is \$1268 million. *Id.* at 21 tbl.5. Dividing this cost by the forecast net capacity of 1481.5 of net capacity (average of summer and winter capacities results in a retrofit cost of 856 dollars per megawatt of net capacity (\$/MW). *Id.* at 19 tbl.4.

80. *Id.*

81. *See generally* Dalia Patiño-Echeverri et al., *supra* note 9 (discussing the costs of such uncertainty).

82. This is a hypothetical decisionmaker, not informed of § 111(d) plans—see CLEAN AIR ACT, *supra* note 5, § 111(d)—and not aware of the proposed rulemaking issued by EPA on June 18—see *supra* note 39.

83. *See generally AEO2014 Early Release Overview*, *supra* note 13 (projecting price volatility of coal and natural gas for power generation in the baseline scenarios).

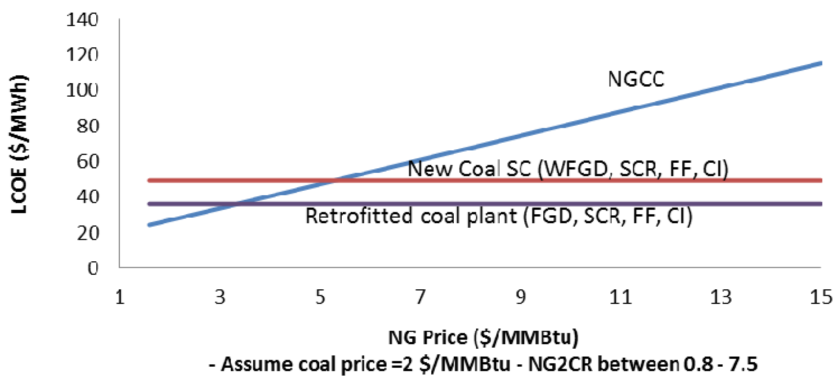
84. Pratson et al., *supra* note 6, at 4930.

NG2CP has exhibited substantial fluctuations. While in February 2007 the NG2CP was at 4.6, in the spring of 2012—when natural gas prices approached a ten-year low close to two dollars per million British thermal units ($/MMBtu)[85]—the NG2CP reached an unusually low value below 1. For 2014, the average value of the NG2CP has bounced back to 1.61.[86] Given these large fluctuations in price, it is very difficult for investors to make long-term decisions between compliance alternatives.

Figure 2 illustrates the challenges of choosing between retrofitting the existing plant or installing a new coal or gas plant given uncertainty about fuel prices. The Figure shows the estimated levelized cost of electricity (LCOE) for a retrofitted plant and for new coal- and gas-fired power plants, independent of future emissions controls or early plant retirement variables. The model assumes that possible retrofits include flue gas desulfurization systems (FGDs) to reduce SO_2 and mercury emissions, selective catalytic reduction (SCR) to reduce NOx emissions, fabric filters (FFs) to reduce particulate matter (PM) and mercury emissions, and carbon injection (CI) to reduce mercury emissions. The model utilizes the costs and performance figures for these retrofit technologies that were reported in the Mills Creek proposal.[87] The replacement coal plant is assumed to be a new supercritical pulverized coal (SCPC) plant fully equipped with a wet flue gas desulphurization system (WFGDs), SCR, an FF, and CI to control SO_2, NOx, mercury, and PM emissions. The natural gas plant is a natural gas combined cycle (NGCC) power plant. For simplicity, the Figure assumes that coal prices stay at 2 $/MMBtu and that natural gas prices vary from 1.6 $/MMBtu to 15 $/MMBtu (which is equivalent to an NG2CR ranging between 0.8 and 7.5). If natural gas prices are 3 $/MMBtu or lower, an NGCC plant should be chosen since its LCOE would be lower than the LCOE of a retrofitted coal plant or new SCPC plants. If retrofit costs are higher than what is assumed here and investors are only considering new plant installations, then an expectation that natural gas prices will remain below 5 $/MMBtu would motivate investment in an NGCC plant rather than in an SCPC plant.

85. *Id.* at 4931 fig.4.
86. *See Electricity Monthly Update*, U.S. ENERGY INFO. ADMIN. (MAR. 21, 2014), http://www.eia.gov/electricity/monthly/update/resource_use.cfm (showing that the prices in December 2013 for Central Appalachian Coal and Natural Gas Henry Hub were 2.72 and 4.38 dollars per million British thermal units ($/MMBtu), which results in a gas-to-coal price ratio of 1.61).
87. *See* Hoppock, *supra* note 79 (presenting costs assumptions and analysis of the investment decision of Kentucky Gas and Electric regarding the retrofits of the Mills Creek Plant to achieve compliance with new and proposed EPA rules).

FIGURE 2. Levelized Costs of Electricity for Retrofitted and New Plants



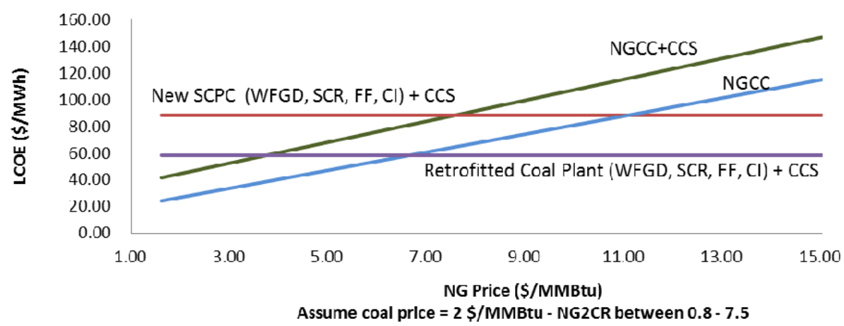
The figure depicts levelized costs of electricity for a retrofitted plant and for new NGCC and SCPC plants as a function of varying natural gas prices. Capital costs for the retrofitted plant are assumed to be 857 $/kW net.[88] Capital costs for new plants are assumed to be 1853 $/kW net for SCPC plants and 778 $/kW net for NGCC plants.[89] Capital costs are annualized assuming a fixed charge factor of 0.1128 and a capacity factor of 75 percent.

The model in Figure 2 is incomplete, however as it ignores potential legal requirements to install CCS in both new and existing plants. The EPA's proposed GHG emissions standards for new plants find CCS as the Best System of Emission Reduction (BSER), and hence require new plants to achieve an average emissions rate that can only be achieved with CCS installation.[90] Although EPA proposed rules for existing plants[91] refrain from identifying CCS as a component of the BSER for existing Electric Generating Units (EGU), CCS could be mandated by states, as is available to States and sources as a compliance option.[92] Therefore, the true cost comparison ought to be between the cost of electricity for an NGCC plant and the cost of electricity for an SCPC plant or a retrofitted plant that also includes CCS, as shown in Figure 3. Natural gas prices would have to be above 6.6 $/MMBtu to justify a CCS retrofit. If NGCC plants were also required to include CCS equipment, then any natural gas prices above

88. David Hoppock et al., *supra* note 79.
89. As estimated by IECM version 8.0.2. *See Welcome to the Integrated Environmental Control Model*, CARNEGIE MELLON, http://www.cmu.edu/epp/iecm/about.html (last visited Apr. 2013) (access Integrated Environmental Control Model (IECM) version 8.0.2 by clicking on "Download IECM" to access IECM program) [hereinafter *IECM*].
90. Carbon Pollution Standards for New Fossil Fuel-Fired Electric Generating Units (EGUs), 79 Fed. Reg. at 1430.
91. *See supra* note 39.
92. *See id.* at 34,857.

4.6 $/MMBtu would make a CCS retrofit preferable. If a CCS retrofit is not being considered (or is much more expensive than what is portrayed here), then natural gas prices would need to be above 11 $/MMBtu to make a new SCPC plant preferable to an NGCC plant. If the new NGCC was also required to have CCS equipment, then any natural gas price above 7.5 $/MMBtu would justify building a new coal plant.

FIGURE 3. Levelized Costs of Electricity for Retrofitted and New Plants Including Carbon Capture and Sequestration (CCS) Equipment



The figure depicts levelized costs of electricity for a retrofitted plant and for new NGCC and SCPC plants that include CCS equipment as a function of varying natural gas prices. Capital costs for all retrofits including CCS equipment are assumed to be 2019 $/kW net. Capital costs for new plants with CCS equipment are assumed to be 3232 $/kW net for SCPC plants and 1360 $/kW net for NGCC plants[93]. Capital costs are annualized assuming a fixed charge factor of 0.1128 and a capacity factor of 75 percent.

In May 2014, the U.S. Energy Information Administration (EIA) reported a probability of about 20 percent that natural gas prices will exceed 5 $/MMBtu by August 2014.[94] But uncertainty about long term natural gas prices remains high. The EIA projections of natural gas prices for the next three decades differ by about 1 $/MMBtu depending on assumptions about the number of wells and the level of shale gas recovery per well.[95] Growing demand for natural gas in Eu-

93. *See id.*
94. *See* U.S. ENERGY INFO. ADMIN., SHORT-TERM ENERGY OUTLOOK. MARKET PRICES AND UNCERTAINTY REPORT, at Figure 16 (2014), *available at* http://www.eia.gov/forecasts/steo/uncertainty/index.cfm.
95. *See* U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2013 WITH PROJECTIONS TO 2040, at 176 tbl.C3 (2013) (projecting that the price of natural gas delivered to electric power generators will grow steadily by 2 percent annually). These projections predict natural gas prices for

rope and Asia (and the associated possibility that liquefied natural gas exports may raise domestic prices in the United States) exacerbates this uncertainty about future prices.[96] Given this long-term uncertainty, the choice between a new coal power plant and a new natural gas power plant is not as easy as current prices may suggest.

In summary, the prospects of low natural gas prices and GHG constraints on coal plants make the option of replacing existing coal-fired power plants with an NGCC plant look very attractive, but uncertainty about both variables may make investors prefer to wait until more information becomes available.

B. The Option of Delaying the Investment Decision

Given that capital investment decisions are for the most part irreversible and must be made under uncertainty about many variables that affect their outcome, the option of delaying investment until more information is revealed (or, in other words, waiting to make a decision) is often valuable.[97] Regulations that take away this option can only decrease investors' profits or leave them unchanged; in no case will eliminating this option increase profits. As a consequence, investors may be willing to pay to keep flexible investment options available.

The methods and techniques of real options valuation can be used to approximate the value of the option to wait or other options such as installing emissions controls in stages or mothballing an existing plant.[98] These methods require regulators to identify investors' expected uncertainty over time regard-

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the years 2030 and 2040 of 6.05 and 8.38 \$/MMBtu respectively. *Id.* Under a low oil and gas resource scenario, the projected prices for the years 2030 and 2040 grow to 6.55 and 9.34 \$/MMBtu respectively. *Id.* All dollar amounts are in 2011 dollars. *Id.*

96. *See International Energy Outlook 2013*, U.S. ENERGY INFO. ADMIN. 46–47 (July 2013), http://www.eia.gov/forecasts/ieo/pdf/0484(2013).pdf (stating under the reference case, natural gas consumption in OECD Asia grows on average by 1.3 percent per year from 2010 to 2040 and that natural gas consumption in non OECD Asia grows on average by 3.3 percent annually). The report also states that U.S. LNG exports are expected to start in 2016 and that export of LNG depend on a number of factors that are hard to anticipate and hence projections are highly uncertain. *Id.* at 57.

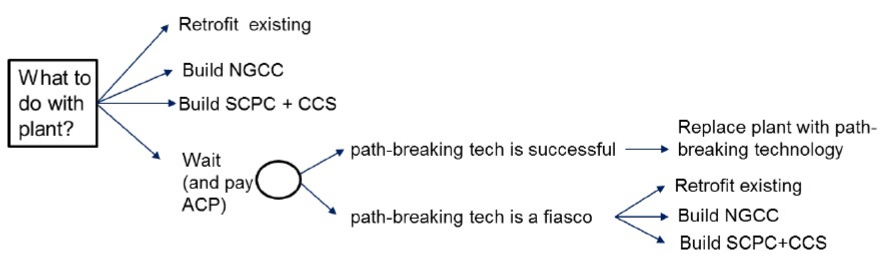
97. *See generally* Robert McDonald & Daniel Siegel, *The Value of Waiting to Invest*, 101 Q.J. ECON. 707, 707–27 (1986).

98. Real options theory is different from traditional net present value (NPV) analysis, which operates under the rule that investment should be undertaken whenever the expected NPV of revenues exceeds that of costs. Under real options theory, investment should be undertaken only if the expected NPV of revenues exceeds the NPV of costs plus the cost of forgoing the opportunity to postpone the investment. Real options theory recognizes that investment means killing the option to wait; given that the option to wait has value, killing this option implies a cost that needs to be added to the investment analysis. *See generally* AVINASH K. DIXIT & ROBERT S. PINDYCK, INVESTMENT UNDER UNCERTAINTY (1994).

ing the variables that will affect the outcome of the investment decision (such as future coal and natural gas prices, future costs and performance of different technologies, and future environmental regulations).[99] In this Article, I assume that investors' uncertainty about the relative prices of coal and natural gas will remain the same over the next few years. However, I assume that pathbreaking technologies are under development and are being tested in the next few years. Therefore, plant owners having the option of waiting to invest until the uncertainty on the technology's success is resolved could result in economic benefits for investors.

Figure 4 illustrates the decision tree for an owner of an existing coal-fired power plant when the possibility of a pathbreaking technology for electricity generation is considered.[100] Note that considering the possibility of a pathbreaking technology only makes sense if there is an option to wait until uncertainty about the technology's success is reduced or resolved; if the investor chose to retrofit or replace the coal plant, it would be prohibitively expensive to subsequently replace the newly-built plant with a plant that utilized the successful pathbreaking technology.

FIGURE 4. Decision Tree for the Investment Decision Facing Owners of a Coal-Fired Power Plant When the Option of Paying an ACP Exists



The tree denotes the decisions that an owner of an existing coal-fired power plant needs to consider when there is a possibility to pay an ACP to delay investment and find out if a pathbreaking technology for electricity generation is successful.

How much investors should pay for the option to wait depends on at least two factors: (1) the probability that the pathbreaking technology will turn out to be viable; and (2) the economic benefits obtained by investors from replacing an

99. The uncertainty on these variables can be described with a time-varying stochastic process such as geometric Brownian motion (gbm) or mean reverting processes. *See* SAMUEL KARLIN & HOWARD M. TAYLOR, A FIRST COURSE IN STOCHASTIC PROCESSES (2d ed. 1975).

100. This tree is a subset of the decision tree presented in Figure 1.

old coal plant with the pathbreaking technology. In turn, the potential economic benefits of replacing an existing plant with a plant that utilizes the successful pathbreaking technology depend on two other variables: (1) the performance and costs of the pathbreaking technology; and (2) the capital and operating costs of retrofitting the existing plant or installing a new one.[101]

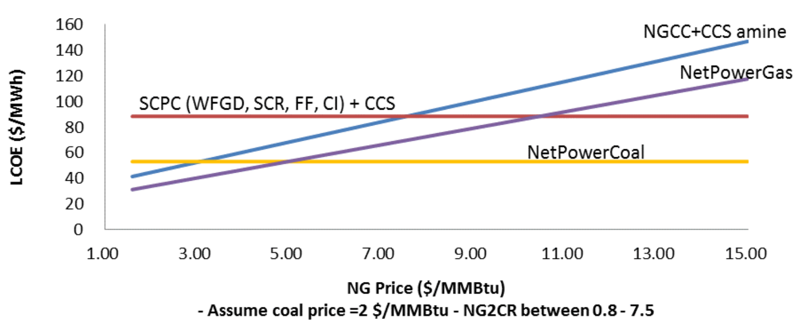
As an example of a pathbreaking technology, I consider NET Power, an oxyfuel power cycle technology that promises cost-effective electric power with no air emissions.[102] Shaw, Toshiba and Exelon have partnered with NET Power to build a twenty-five megawatt electrical (MWe) natural gas plant that utilizes a high-pressure, supercritical carbon dioxide cycle.[103] The company has won a competition and has been granted £4.9 million from the U.K. Department of Energy.[104]

If successful, the system would run with either coal or natural gas, and would have no air emissions other than pipeline-quality, high-pressure CO_2.[105] A NET Power plant would also be much more efficient than conventional technologies, allowing for significant reductions in the cost of electricity. It is expected that a coal-fired NET Power plant would have an efficiency of 49 percent, while a gas-fired plant would have an efficiency of 53 percent.[106] In comparison, a new SCPC plant—fully equipped with emissions-control equipment for SO_2, NOx,

101. *See* Patiño-Echeverri et al., *supra* note 61 (presenting an analytical model of the potential benefits of postponing investment in an immature technology such as CCS).
102. *See* R.J. Allam et al., *High Efficiency and Low Cost of Electricity Generation from Fossil Fuels While Eliminating Atmospheric Emisssions, Including Carbon Dioxide*, 37 ENERGY PROCEDIA 1135, 1135–49 (2013) (describing the NET Power technology).
103. Jen Wilson & Toshiba Joins Shaw, *Exelon on NET Power Project*, CHARLOTTE BUS. J. (June 15, 2012, 1:47 PM), http://www.bizjournals.com/charlotte/news/2012/06/ 15/toshiba-joins-shaw-exelon-on-net.html.
104. *NET Power Receives Grant from the UK Department of Energy and Climate Change to Support Development of Breakthrough, Clean Power Technology*, PR NEWSWIRE, Nov. 21, 2012, http://www.prnewswire.co.uk/news-releases/net-power-receives-grant-from-the-uk-department-of-energy-and-climate-change-to-support-development-of-breakthrough-clean-power-technology-180322251.html.
105. *See* Allam et al., *supra* note 102, at 1137.
106. *Id.* NET Power reports expected efficiencies using the lower heating value (LHV). All efficiency values in this Article are reported in High Heating Value (HHV) units. The heating value is the amount of heat produced by combustion of a unit quantity of a fuel. HHV is the amount of heat produced by the complete combustion of a unit quantity of fuel. It is obtained when all products of the combustion are cooled down to the temperature before the combustion and the water vapor formed during combustion is condensed. LHV is obtained by subtracting the latent heat of vaporization of the water vapor formed by the combustion from the gross or higher heating value. The conversion from LHV to HHV depends on the fuel. Compared with LHV efficiency, HHV efficiency is 4 percent lower for coal and 10 percent lower for natural gas. *See* NATIONAL RESEARCH COUNCIL, COAL: ENERGY FOR THE FUTURE 272 (1995).

mercury and PM[107]—would have an efficiency of 39 percent, while a new NGCC plant would have an efficiency of 50 percent.[108] This turns out to be a 10 percent efficiency gain for coal-fired NET Power plants over SCPC plants and a 3 percent gain for gas-fired NET Power plants over NGCC plants. Although this is already a significant improvement, these numbers do not reflect the true efficiency differentials between NET Power plants and traditional plants. As discussed above, the current regulatory environment requires owners of conventional plants to install CCS equipment in order to meet stringent emissions standards. Therefore, the efficiency of a NET Power plant needs to be compared with that of a conventional plant that utilizes CCS equipment. An SCPC plant with amine-based CCS has an efficiency of about 29 percent, and an NGCC with amine-based CCS has an efficiency of about 43 percent. Comparing these numbers to the efficiencies of NET Power plants reveals that the efficiency advantages of the NET power system compared with conventional plants are 20 percent and 10 percent for coal- and gas-fired plants respectively.[109] Figure 5 shows that if the system can be scaled to larger capacities while meeting expected performance benchmarks, other technologies would be obsolete in comparison.

FIGURE 5. Levelized Costs of Electricity for New Plants with CCS and Net Power Plants



The figure depicts Levelized Costs of Electricity for new NGCC and SCPC plants that include CCS equipment and compares them to coal and gas-fired Net Power plants.

107. *See IECM*, *supra* note 89.
108. *See id.*
109. *See id.*

III. FLEXIBLE MANDATES AS AN ALTERNATIVE TO TRADITIONAL PERFORMANCE STANDARDS

Is there a flexible mandate that can achieve the same or superior environmental goals as an inflexible standard while reducing compliance costs? Previous work has examined the feasibility of designing a new source performance standard (NSPS) for CO_2 that maintains the investor's option of building new coal-fired power plants without CCS equipment while at the same time accomplishing the same environmental goals of an NSPS policy that requires that all new coal-fired plants be installed with CCS equipment.[110] This previous work shows that an environmental regulation in the form of a new source flexible technology standard with the option for plant owners to make an alternative compliance payment (FlexACP) is likely to achieve or exceed the environmental targets of a traditional inflexible NSPS.[111] In this Part, I investigate whether is it possible to design a successful FlexACP policy for existing plants that gives plant owners the option to wait for pathbreaking technologies to materialize.

Designing flexible mandates for existing plants is challenging in light of the fact that standards for existing plants target not only CO_2 emissions but also SO_2, NOx, mercury, and PM emissions.[112] The additional difficulty derives not so much from the need to find different FlexACP values to meet emissions targets for each pollutant; rather, the problem is that agreeing on a time value for those pollutants may be even more challenging than agreeing on the time value of CO_2 capture. Specifying a time value requires regulators to decide on an appropriate discount rate to use for aggregating emissions across different periods. To keep things simple I will treat all emissions reductions as equivalent regardless of the time at which they occur, and consistently will not discount emissions reductions.[113]

110. *See* Patiño-Echeverri et al., *supra* note 61.
111. *Id.* at 142–46.
112. The Cross-State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards (MATS) target SO_2, NOx, PM, and mercury emissions. *See generally Cross-State Air Pollution Rule (CSAPR)*, U.S. ENVTL. PROT. AGENCY, http://www.epa.gov/airtransport/CSAPR/ index.html (last visited Mar. 3, 2014); *Mercury and Air Toxics Standards (MATS)*, *supra* note 7.
113. Using a discount rate of zero corresponds to the vision that reducing emission in the future is as important as reducing them in the present. If present emission reductions were more valuable compared to the future then any policies that allow emitting in the present in exchange for increased emissions reductions in the future would need to be even more stringent and demand an even higher future emissions reductions. For a discussion on discount rates and climate policy see Kenneth R. Richards, *The Time Value of Carbon in Bottom-Up Studies*, 27 CRITICAL REVIEWS IN ENVTL. SCI. & TECH. (SPECIAL ISSUE) S279, S279-S292 (1997).

I begin by assuming that traditional existing source performance standards (ESPSs) are in place for each of the following pollutants: CO_2, SO_2, NOx, mercury, and PM. Under this policy plants achieve compliance by installing pollution controls that bring emissions for each pollutant down to the standard. This Article proposes substituting FlexACPs in place of these ESPSs. The FlexACP for each pollutant has two attributes: (1) the value of the alternative compliance payment (ACP); and (2) the year of expiration of the flexibility period (denoted by v). Under a FlexACP policy plants may achieve compliance by either installing pollution controls or paying ACPs for each unit of emissions of each pollutant in excess of the prescribed standards for the duration of the flexible period. If a plant owner opts to pay the ACPs, he must choose to either retire the plant or install pollution controls at the end of the flexible period. I assume that the pathbreaking technology has a probability π of proving to be successful at the beginning of year v. To ensure that the FlexACP is a true alternative to the ESPS, it is essential that regulators select a flexibility period that is equal to the time it will take to determine whether the pathbreaking technology is successful.

For a FlexACP to be superior to an ESPS, it needs to achieve the same or higher emissions reductions at the same or lower cost. Hence, the first condition for a successful FlexACP is that the expected net present value of cumulative emissions under a FlexACP should not exceed cumulative emissions under an ESPS.

A. Exploring the Creation of a FlexACP Policy That is Environmentally Superior to an ESPS Policy

Estimating the emissions under a flexible or traditional policy requires making assumptions about the compliance choices that investors will make. As discussed above, an investor's choice between retrofitting or replacing his plant will be determined by his beliefs about future fuel prices and emissions regulations. I start by considering the case of a plant like Mills Creek, for which the best option today seems to be to invest in retrofits. Under an ESPS, the plant would be retrofitted and operated for the remaining years of its economic life (denoted by T). I assume that the conditions that make retrofitting the preferred choice will remain the same at the end of the flexibility period; the plant will be retrofitted if the pathbreaking technology proves to be unsuccessful at that time. Therefore, under a FlexACP, the plant will operate without retrofitting for $v-1$ years; thereafter there is a probability π that the plant will be replaced with a plant that utilizes the pathbreaking technology and a probability $1-\pi$ that the plant will be retrofitted with conventional emissions control equipment. Given that the pathbreaking technology is assumed to achieve greater emissions reductions than the conventional emissions control equipment, the expected cumulative emissions under a FlexACP will be lower than those under an ESPS as long as the probability of success π is high enough.

Equation 1 states the first requirement for a successful FlexACP: namely, that the cumulative emissions under an ESPS (represented by the left-hand side of the Equation) are greater than or equal to the expected emissions under a FlexACP. I use $e^{retrofit}$ to denote the annual emissions (for any given pollutant) of a retrofitted plant, $e^{uncontrolled}$ to denote the annual emissions of an uncontrolled plant, and e^{best} to denote the annual emissions of a new plant using the pathbreaking (best) technology.

EQUATION 1.

$$\sum_{t=1}^{T} e^{retrofit} \geq \sum_{t=1}^{v-1} e^{uncontrolled} + \pi \sum_{t=v}^{T} e^{best} + (1-\pi) \sum_{t=v}^{T} e^{retrofit}$$

If the annual emissions of the retrofitted plant, the uncontrolled (unretrofitted) plant, and the plant utilizing the pathbreaking technology are known, then we can solve for the minimum value of π that would make the FlexACP have lower expected emissions than the ESPS policy. Assuming that emissions controls for the given pollutant reduce emissions by a factor of $1 - R$, then the remaining emissions of a retrofitted plant can be expressed in terms of those of an uncontrolled plant as:

EQUATION 2.

$$e^{retrofit} = Re^{uncontrolled}$$

Assuming that the pathbreaking technology is the NET Power technology discussed above, the emissions of a plant utilizing the pathbreaking technology can be expressed as:

EQUATION 3.

$$e^{best} = 0$$

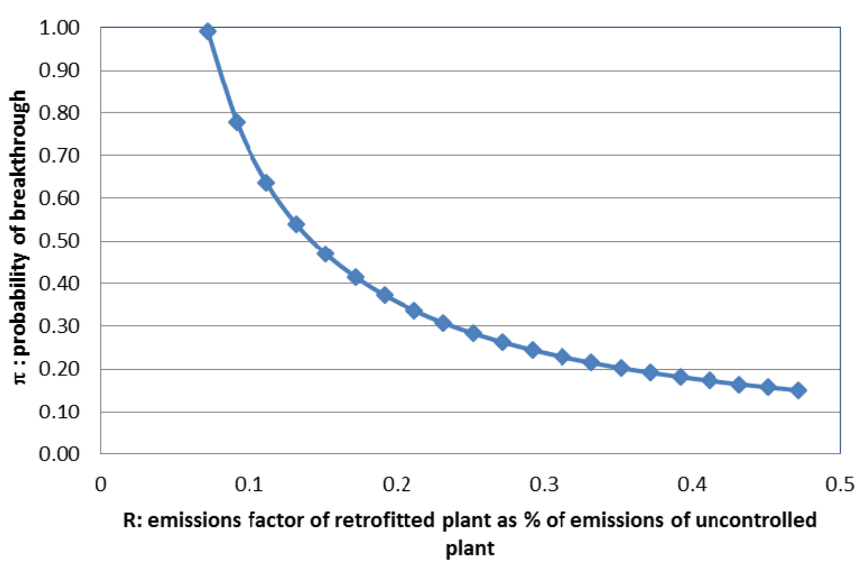
By replacing the placeholders in Equation 1 with the emissions values in Equation 2 and Equation 3, we obtain an expression that allows us to calculate the minimum probability of success for the pathbreaking technology (the threshold probability) that will make a FlexACP environmentally superior to an ESPS.

EQUATION 4.

$$\pi \geq \frac{v-1}{(T-v+1)R}$$

Finding the threshold probability requires us to specify the planning horizon (T), the time until the success of the pathbreaking technology is known (v), and the percentage of emissions remaining after pollution controls have been installed (R). Figure 6 illustrates the minimum value of π that would make a FlexACP environmentally superior to an ESPS. The threshold probability is presented as a function of R, where the economic lifetime of the retrofitted plant is assumed to be thirty years and the success of the pathbreaking technology is known in year three.

FIGURE 6. Minimum Value of π (Probability of Success of Path-Breaking Technology) That Would Make a FlexACP Policy Environmentally Superior to an ESPS Policy

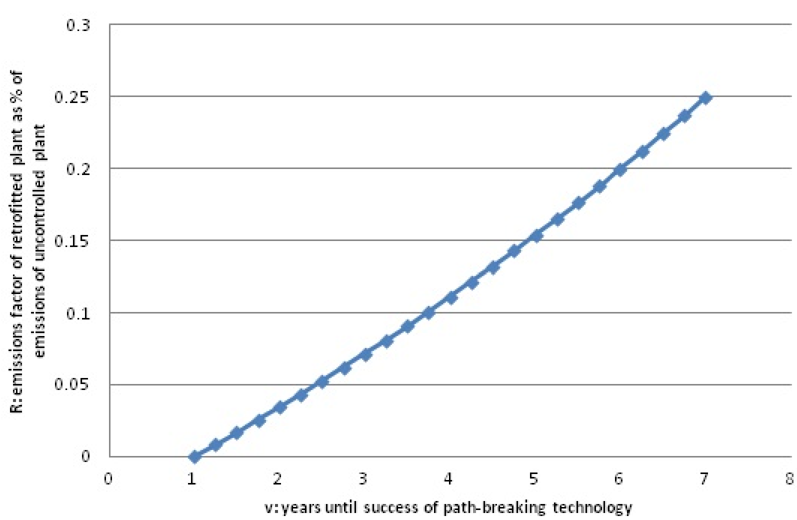


The Figure depicts the Minimum probability of path-breaking technology success that would make a flexible policy feasible. The required probability of success depends on the efficiency of environmental controls as expressed in terms of the remaining percentage of emissions of a facility retrofitted with such control. Graph assumes 30 years for the life time of a retrofitted plant and 3 years for the time before success of path-breaking technology is known.

The R value for which π is equal to 1 denotes the R value for which it is impossible to design a FlexACP policy that is environmentally superior to an ESPS policy. In Figure 6, π is equal to 1 when R is equal to 0.07. This means that for any pollutant for which there already exists an emissions control capable of reducing emissions by 93 percent or more, no FlexACP can possibly achieve lower cumulative emissions than an ESPS policy that mandates immediate retrofit.

Figure 7 assumes the pathbreaking technology is guaranteed to materialize in v years (that is, π is equal to 1) and shows the maximum value of R for which an environmentally superior FlexACP does not exist. For example, if we had to wait six years for the success of a pathbreaking technology, it would be impossible to find an environmentally superior FlexACP for any pollutant for which there are controls that can reduce emissions by 75 percent or more (in other words, the remaining emissions after retrofit are at or below 25 percent of their pre-retrofit levels).

FIGURE 7. Maximum Value of R (Remaining Emissions From Conventional Emission Control) for Which a FlexACP Policy Environmentally Superior Than the ESPS Does Not Exist



The Figure depicts the maximum efficiency of conventional emissions-control-equipment that would allow the existence of a superior FlexACP policy. If remaining plant emissions are below this threshold plant owners should not wait until a path-breaking technology is ready for an installation.

This analysis shows that the efficacy of current retrofit emissions control technologies determines whether or not a FlexACP can be environmentally superior to an ESPS. Table 1 lists the emissions control equipment that could be used to reduce emissions for each type of pollutant from an existing coal-fired power plant, along with their respective R values. The efficacy of fabric filters at reducing emissions of particulate matter makes it impossible to design an environmentally superior FlexACP for PM when the lead time for success of the pathbreaking technology is three years. Similarly, fabric filters combined with carbon injection reduce 97 percent of the emissions of elemental mercury. Hence, for this pollutant it is impossible to design a sensible FlexACP.

TABLE 1. Efficacy of Emissions Controls in a Supercritical Coal-Fired Power Plant as Reported by Carnegie Mellon's Integrated Environmental Control Model IECM Version 8.0.2.[114]

Pollutant	Emissions control equipment	Emissions of uncontrolled plant (lbs/MMBtu)	Emissions after retrofit (lbs/MMBtu)	R
CO_2	CCS Amine	204	20.4	0.100
SO_2	Wet FGD	3.117	0.6038	0.194
NO_2	Hot Side SCR	0.5656	0.12	0.212
PM	Fabric Filter	4.4	2.95E-02	0.007
Mercury elemental	Carbon Injection + Fabric Filter	2.40E-06	7.19E-07	0.300
Mercury oxidized		5.59E-06	1.68E-06	0.300
Total Mercury		7.99E-06	2.40E-06	0.300

All values assume the default IECM subcritical plant and emissions control configurations except for NOx where actual NOx removal efficiency has been set to 78 percent to achieve emission rate of close to 0.12lbs/MMBtu. The reported value of emissions after retrofit for each pollutant only considers the reductions achieved with the specific emissions control equipment. If all controls are operated simultaneously there are synergies in their operation and emissions reductions of SO_2 and PM are lower.

For a FlexACP to be economically superior to an ESPS, the cumulative LCOE under a FlexACP over the lifetime of the plant must be less than or equal to the LCOE under an ESPS. Once again, estimating investors' costs under a flexible or traditional policy requires regulators to make assumptions about inves-

114. *See IECM*, *supra* note 89.

tors' compliance choices. Again, an investor's choice between retrofitting or replacing his plant will be determined by his beliefs about future fuel prices and emissions regulations. For illustration, I consider the case of an existing plant for which the best option today seems to be to replace the plant with a new plant utilizing conventional natural gas or coal technology. I assume that the conditions that make replacing the plant the preferred option will remain the same at the end of the flexibility period, so the plant will be replaced at the end of the period if the pathbreaking technology proves to be unsuccessful.

Equation 5 shows the second requirement for a successful FlexACP, which is that the net present value of the LCOE over the lifetime of the plant under an ESPS (represented by the left-hand side of the Equation) must be greater than or equal to the cumulative LCOE under a FlexACP. During the first $\upsilon - 1$ years, the LCOE under a FlexACP is equal to the LCOE of the uncontrolled plant plus the ACP (expressed in \$/MWh). From year v on, the expected LCOE under a FlexACP will be the LCOE of a new plant utilizing the successful pathbreaking technology ($LCOE_t^{best}$) multiplied by probability π, then added to the LCOE of the conventional new plant ($LCOE_t^{conv}$), and finally multiplied by probability $1 - \pi$. The Equation assumes a discount factor d_t that brings to present value a monetary amount from future year t.

EQUATION 5.

$$\sum_{t=1}^{T} d_t LCOE_t^{conv} \geq \sum_{t=1}^{v-1} d_t \left(LCOE_t^{unc} + ACP \right) + \pi \sum_{t=v}^{T} d_t LCOE_t^{best} + (1-\pi) \sum_{t=v}^{T} d_t LCOE_t^{conv}$$

Assuming the LCOE stays constant ($LCOE_t = k$ for all t), we can drop the discount factor and solve for the maximum ACP (expressed in \$/MWh) that an investor would be willing to pay:

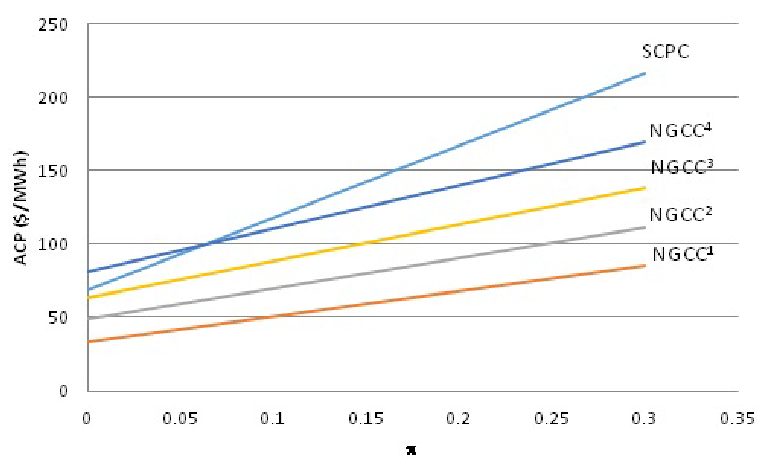
EQUATION 6.

$$ACP \leq LCOE^{conv} - LCOE^{unc} + \pi \left(\frac{T - \upsilon + 1}{\upsilon - 1} \right) \left[LCOE^{conv} - LCOE^{best} \right]$$

If the chances that the pathbreaking technology will be successful are null ($\pi = 0$), then investors should be willing to pay up to the difference between the LCOE of the new conventional plant and the LCOE of the uncontrolled plant. However, if there is any chance that the pathbreaking technology will be successful, investors would be willing to pay an additional amount for the chance to save money in the future (since, as discussed above, the LCOE of a plant using the pathbreaking technology would be lower than the LCOE of a new conventional plant). For any given positive value of π, the amount investors are willing to pay will increase as the difference between the LCOE of a plant utilizing pathbreaking technology and the LCOE of a conventional plant increases. The longer the time until the pathbreaking technology will materialize, the less investors should be willing to pay.

Figure 8 illustrates the maximum ACP that investors will be willing to pay given different levels of replacement technology and varying fuel prices. Given the significant efficiency advantages of the pathbreaking technology, investors will be willing to pay a high ACP even when the probability of the pathbreaking technology's success is low. For example, investors would be willing to pay up to 50 $/MWh or more (depending on the replacement technology being considered as an alternative) if the chances of a pathbreaking technology like NET Power emerging in the next two years were 10 percent or greater.

FIGURE 8. Maximum ACP Payment That Would Make a FlexACP Less Costly Than an ESPS Policy



The figure depicts the maximum ACP payment (expressed in $/MWh) that would make a FlexACP less costly than an ESPS policy. It is assumed the probability that a pathbreaking technology will emerge is π, the planning horizon is thirty years, and the flexibility period expires in year three. The SCPC line assumes that investors' alternative would be to replace the existing plant with an SCPC plant and that fuel prices would stay at 2 $/MMBtu. The NGCC lines assume that investors' alternative would be to replace the old plant with a new NGCC plant . $NGCC^1$ assumes that natural gas prices stay at 3 $/MMBtu, while $NGCC^2$, $NGCC^3$, and $NGCC^4$, assume prices of 5, 7, and 9 $/MMBtu respectively. All lines assume that the uncontrolled plant has an LCOE of 20 $/MWh.

DISCUSSION AND CONCLUSIONS

Incorporating flexibility into Clean Air Act[115] regulatory policies for existing sources can potentially contribute to the development and deployment of much-needed innovative electricity-generation technologies without compromising environmental goals or economic efficiency. Given available information on current retrofit and replacement plant technologies, and using the NET Power plant as an example of a possible pathbreaking technology, this Article finds that it is possible to design a FlexACP that reduces SO_2, NOx, and CO_2 emissions. However, it is unlikely that a FlexACP can reduce emissions or lower emissions control costs for particulate matter or elemental mercury. These results suggest that an ideal FlexACP policy that allows some plants to delay plant replacement or expensive retrofitting could be environmentally superior to an ESPS policy, so long as retrofits of fabric filters and carbon injection technology are timely installed. Given this initial indication that it is possible to design a successful FlexACP policy, it may be valuable to explore in more depth the technical and legal aspects of the design of such a policy. A thorough analysis of the outcomes of a FlexACP-type policy must look at its potential impacts in an equilibrium approach.

115. *See* CLEAN AIR ACT, *supra* note 5.