Florida State University Law Review

Volume 43 | Issue 1 Article 3

Fall 2015

Maximizing Utility in Electric Utility Regulation

Jonas J. Monast
Duke Law School

MAXIMIZING UTILITY IN ELECTRIC UTILITY REGULATION

JONAS J. MONAST*

ABSTRACT

The electric power sector is undergoing a period of profound change, reacting to economic, technological, and regulatory variables that have emerged quickly and largely without warning. In many states, the public utility commission (PUC) will play a key role in determining how electric utilities respond to these rapidly changing circumstances, the outcome of which will affect electricity rates, investor returns, public health, and local and state economies for decades to come. The general mandate underlying many utility commission proceedings—seeking the least cost option for maintaining a reliable electricity sector—provides the PUC with considerable discretion to choose among sources of information, potential outcomes, and risk assessments.

The least cost framework is generally treated as an objective standard, but a close examination of PUC decisions demonstrates the inherent subjectivity and the value choices commissioners face when determining which electric utility decisions are in the public's best interest. From a descriptive perspective, the effort to maximize societal benefits and minimize societal costs associated with electricity generation and delivery is, at its core, a utilitarian exercise. Like the concept of welfare maximization that lies at the heart of the classic utilitarian framework, the cost minimization goal seeks to produce the greatest good for the greatest number through an affordable and reliable electricity sector. From the normative perspective, accepting that PUC decision-making is a utilitarian exercise invites a critical assessment of whether PUCs are succeeding in implementing the least cost mandate. This Article provides an overview of PUC decision-making and the least cost framework, then examines the inherent discretion in the least cost mandate by analyzing four recent PUC decisions where commissioners reach opposing decisions based on the same set of facts. The Article concludes by proposing mechanisms for capturing broader societal benefits through an expanded application of the PUCs' existing discretion.

* Senior Lecturing Fellow at Duke Law School and Director of the Climate & Energy Program at Duke University's Nicholas Institute for Environmental Policy Solutions. This project benefits from the insights and feedback of many people. First and foremost, I would like to express my sincere gratitude to my father, Joseph Monast, Ph.D., for early discussions that led to this paper and for sparking my interest in education and scholarship. I would also like to thank Sarah Adair, Jim Salzman, Victor Flatt, William Buzbee, Emily Hammond, Richard Levy, David Spence, Joel Eisen, Robert Glicksman, and Jedediah Purdy, and the participants in Vermont Law School's 5th Annual Colloquium on Environmental Scholarship and the Jan. 15, 2015 UNC faculty workshop for the comments on early drafts of this article. Any errors or omissions are my own.

I. INTRODUCTION

The electric power sector is undergoing a period of profound change, reacting to economic, technological, and regulatory factors that have emerged quickly and largely without warning. The combination of low natural gas prices and more stringent limits on mercury and other toxic emissions is driving the retirement of a large number of coal-fired power plants.[1] Rooftop solar is emerging as a potentially disruptive force due to the rapid decrease in the cost of photovoltaic panels, renewable energy tax credits, net metering policies, and third party leasing models that allow consumers to install solar at no upfront cost.[2] Nationally, electricity demand dropped significantly during the 2008–2009 economic downturn and is projected to remain relatively flat due to efficiency improvements throughout the economy.[3] In addition, the U.S. Environmental Protection Agency (EPA) promulgated performance standards in August 2015 to limit carbon dioxide (CO_2) emissions from both new and existing fossil fuel-fired power plants.[4] The combination of factors, and the pace at which they have emerged, introduces a significant degree of uncertainty as utilities and state regulators consider multibillion-dollar decisions that will impact the makeup of the electricity sector for decades to come.

In many states, the public utility commission (PUC)[5] plays a key role in determining how electric utilities respond to these rapidly

1. *Projected Retirements of Coal-Fired Power Plants*, U.S. ENERGY INFO. ADMIN. (July 31, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7330.

2. *See* Diane Cardwell, *On Rooftops, a Rival for Utilities*, N.Y. TIMES (July 26, 2013), http://www.nytimes.com/2013/07/27/business/energy-environment/utilities-confront-fresh-threat-do-it-yourself-power.html?_r=1.

3. *U.S. Economy and Electricity Demand Growth Are Linked, But Relationship Is Changing*, U.S. ENERGY INFO. ADMIN. (Mar. 22, 2013), http://www.eia.gov/todayinenergy/detail.cfm?id=10491.

4. *Clean Power Plan for Existing Power Plants*, U.S. ENVTL. PROT. AGENCY, http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule (last visited Feb. 27, 2016).

5. Utility commissions go by different names in different states, including the Public Service Commission and State Commerce Commission.

changing circumstances, the outcome of which will affect electricity rates, investor returns, public health, and local and state economies. This period of transition provides an important window for reexamining the role of utility commissioners, the values that animate their least cost determinations, and the relationship between environmental impacts and consumer prices. The general mandate underlying many utility commission proceedings—seeking the least cost option for maintaining a reliable electricity sector—provides the PUC with considerable discretion to choose among sources of information, desirable outcomes, and risk assessments. A careful examination of PUC decisions exposes the subjective aspects of the least cost mandate and the value choices embedded in the process that directly influence the outcome.

Consider the quandary of a utility commission when facing the question of whether to invest hundreds of millions of dollars—costs that ratepayers will absorb—to retrofit older coal-fired power plants to comply with new environmental regulations. Ostensibly, the outcome depends upon commissioners' views of future environmental regulations, future natural gas prices, future technological options, and future electricity demand.[6] Economic modeling may assist with the analysis, but the accuracy of modeling results depends on the assumptions made regarding the future, quality of data included in the model, and interpretation of the results.

Furthermore, attempts to quantify future costs and decisions regarding which costs to accept depend on value choices on the part of commissioners evaluating the data. Acknowledging the discretion underlying the least cost mandate allows a more open discussion about what values should be considered. By identifying the embedded values choices, and how those choices impact decisions, stakeholders in the PUC process can better scrutinize the regulatory process to determine whether or not commissions are accomplishing the least cost mandate in actuality.

Decisions regarding the makeup of the electricity sector have wide-ranging economic and environmental impacts. While direct regulation of public health impacts generally falls outside the jurisdiction of the PUC, one view of societal least cost allows consideration of the costs and impacts associated with emissions from power plants into the decision-making processes due to the financial impact of future environmental regulations. The PUC, therefore, need not take

6. *See, e.g.*, David Hoppock et al., *Determining the Least-Cost Investment for an Existing Coal Plant to Comply with EPA Regulations Under Uncertainty* 2 (Nicholas Inst. for Envtl. Policy Sols., Working Paper No. 12-03, 2012), https://nicholasinstitute.duke.edu/sites/default/files/publications/determining-the-least-cost-investment-for-an-existing-coal-plant-to-comply-with-epa-regulations-under-uncertainty-paper.pdf.

on the role of an environmental regulatory agency in order to consider, and potentially mitigate, the environmental impacts of utility-sector investments. As recent history demonstrates, ignoring the potential for future regulations to require additional capital expenditures, and thus raise rates, can be just as significant as ignoring fuel price risk or potential changes in electricity demand.[7]

The effort to maximize societal benefits and minimize societal costs associated with electricity generation and delivery is, at its core, a utilitarian exercise. Like the concept of welfare maximization that lies at the heart of the classic utilitarian framework, the cost minimization goal seeks to produce the greatest good for the greatest number. In the context of traditional electricity sector oversight, the greatest good is generally viewed as affordable and reliable electricity. Also like Jeremy Bentham's pleasure maximization goal, the concept of "least cost" invites differing interpretations, and commission decisions turn on which criteria are considered and how much weight is afforded to each variable.[8]

There is no shortage of opinions regarding the appropriate structure and governance model for the electricity sector.[9] This Article con-

---

7. *See* JAMES E. MCCARTHY, CONG. RESEARCH SERV., R42144, EPA'S UTILITY MACT: WILL THE LIGHTS GO OUT? 4 (2012), http://www.eenews.net/assets/2012/01/19/document_gw_03.pdf (stating that investments to comply with the Utility MATS rule will lead to an average increase of 3.1% ($3–$4 per month) in the cost of electricity and that electricity retail price increases will vary from a low of 1.3% in California to a high of 6.3% in the area served by the Southwest Power Pool, meaning Oklahoma, Kansas, and parts of five other states); OWEN ZINAMAN ET AL., NAT'L RENEWABLE ENERGY LAB., THE EVOLVING ROLE OF THE POWER SECTOR REGULATOR: A CLEAN ENERGY REGULATORS INITIATIVE REPORT 3-4 (2014), http://www.nrel.gov/docs/fy14osti/61570.pdf (stating that raising rates to reflect the true cost of delivered electricity may be necessary to ensure the financial health of the utility and that regulators must consider fuel delivery risks and potential fuel price volatilities to facilitate an energy-secure power sector); *Assessment of EPA's Utility MACT Proposal*, BIPARTISAN POL'Y CTR. (Mar. 24, 2011), http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/Q&A%20Assessment%20of%20MACT%20Rule.pdf (stating that retail electricity prices will increase by an average of 3.7%); *Retail Electricity Price Increases Due to New EPA Rules*, AM. COALITION FOR CLEAN COAL ELECTRICITY (Oct. 2011), http://www.publicpower.org/files/CustomerConnections/ACCCERegionalElectricityPriceMapJune2011.pdf (explaining that MATS increase electricity prices in regions of the United States covering all or part of thirty states, with peak-year increases exceeding ten percent and as high as nineteen percent); Daniel J. Weiss & Zachary Rybarczyk, *Don't Believe the Hype Against EPA Mercury Rules: Opponents Puff Up Costs to Consumers While Ignoring Benefits*, CTR. FOR AM. PROGRESS (Feb. 8, 2012), https://www.americanprogress.org/issues/green/news/2012/02/08/11084/dont-believe-the-hype-against-epa-mercury-rules/ (explaining that on average electricity rates will increase by about 2%).

8. For a discussion of Bentham's theories, see JEREMY BENTHAM, AN INTRODUCTION TO THE PRINCIPLES OF MORALS AND LEGISLATION (London, Oxford University Press Warehouse 1879). *See generally* Hoppock et al., *supra* note 6.

9. *See, e.g.*, SOFIA AIVALIOTI, SABIN CTR. FOR CLIMATE CHANGE, COLUMBIA LAW SCH., ELECTRICITY SECTOR ADAPTATION TO HEAT WAVES 43-44 (2015), http://web.law.columbia.edu/sites/default/files/microsites/climate-change/white_paper_-_electricity_sector_adaptation_to_heat_waves.pdf (arguing that adaptation to climate

tributes to the debate by turning a critical eye toward the application of the least cost mandate. In most states, the existing least cost decision-making framework allows for broad consideration of trends affecting electricity prices and the suite of societal impacts resulting from those decisions. Part II of this Article outlines the current regulatory structure overseeing electric utility decisions, with an emphasis on the role of the state PUC. Part III explores the implicit value choices underlying PUCs' application of the least cost mandate and the range of emerging factors that argue for an expanded view of least cost to best achieve the interrelated goals of affordability, reliability, and minimization of environmental impacts. Finally, Part IV offers a framework for expanding the least cost methodology to consider a wider range of variables and potential societal impacts.

II. THE UTILITY COMMISSION ROLE IN ELECTRICITY SECTOR OVERSIGHT

Regulation of the electricity sector originated at the state level in the early 1900s,[10] with its roots based on the principles that electricity generation and transmission constitute a natural monopoly,[11] centralized control of electricity generation and transmission produces lower prices, and economic regulation is necessary to control the monopoly's exercise of market power.[12] States have retained primary jurisdiction over retail sales of electricity, but over time federal and

---

change requires long-term planning by the electricity sector, as well as engagement, communication, and open dialogue between governments of all levels and other relevant stakeholders); Hal Harvey, *A New Business Model for the Electricity Sector*, HILL (July 15, 2015, 6:34 PM), http://thehill.com/opinion/op-ed/248104-a-new-business-model-for-the-electricity-sector (explaining that utilities should be given a long-term mandate for the core energy goals: affordability, reliability, and a clean environment, and should be rewarded when they exceed the mandates and penalized when they fail); Chris Mooney, *The U.S.'s Energy Infrastructure Will Need Major Changes, Says Obama Report*, WASH. POST (Apr. 21, 2015), http://www.washingtonpost.com/news/energy-environment/wp/2015/04/21/major-changes-needed-for-u-s-power-infrastructure-says-obama-report/ (stating that the energy grid needs to make room for more renewable power).

10. William J. Hausman & John L. Neufeld, *The Market for Capital and the Origins of State Regulation of Electric Utilities in the United States*, 62 J. ECON. HIST. 1050, 1050 (2002).

11. *See* Dayna B. Matthew, *Doing What Comes Naturally: Antitrust Law and Hospital Mergers*, 31 HOUS. L. REV. 813, 822 n.33 (1994) ("During the mid- to late 1800s, John Stuart Mill, responding to the growth of a competitive global economy, coined the term 'natural monopoly' and distinguished these monopolies from 'artificial' monopolies." (citing JOHN STUART MILL, PRINCIPLES OF POLITICAL ECONOMY 448-50 (W.J. Ashley ed., 1909))); Jim Rossi, *Universal Service in Competitive Retail Electric Power Markets: Whither the Duty to Serve?*, 21 ENERGY L.J. 27, 29 (2000) ("[T]he economics of natural monopoly regulation provide the predominant intellectual framework supporting extraordinary obligations for providers of utility services.").

12. *See* William Boyd, *Public Utility and the Low-Carbon Future*, 61 UCLA L. REV. 1614, 1639, 1643-44 (2014).

state regulation of the electricity sector has expanded.[13] Numerous government agencies now oversee the electric utility sector, including state PUCs, state environmental agencies, state energy offices, the U.S. EPA, the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission, and the Department of Energy. Together, these agencies pursue multiple public policy objectives, including: providing affordable and reliable electricity, setting nondiscriminatory prices, maintaining stable prices and avoiding "rate shocks," protecting public health, protecting against environmental harm beyond human health impacts, ensuring energy security, allowing for local economic development, promoting renewable energy, preventing waste by promoting demand-side management and

13. *Id.* at 1628-32.

energy efficiency, and other state policy goals.[14] The result is a complex, and at times, uncoordinated governance structure.[15]

PUCs are products of state laws, and their mandates differ among the states. Nonetheless, there are common approaches to PUC decision-making, such as expecting utilities to seek efficient options for meeting electricity demand, focusing on system reliability,[16] and gov-

14. *See, e.g.*, 16 U.S.C. § 2601 (2012); 16 U.S.C. § 824; 42 U.S.C. § 15801 (2012); 42 U.S.C. § 17001; Public Utilities Act, N.C. GEN. STAT. §§ 62-1 to -50 (2014). The North Carolina Public Utilities Act's lengthy "declaration of policy" highlights the breadth of goals a PUC seeks to achieve, including:

> [P]rovid[ing] fair regulation of public utilities in the interest of the public; promot[ing] the inherent advantage of regulated public utilities; . . . promot[ing] adequate, reliable and economical utility service to all of the citizens and residents of the State; . . . assur[ing] that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs; . . . requir[ing] energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills; provid[ing] just and reasonable rates and charges for public utility services without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices and consistent with long-term management and conservation of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy; . . . assur[ing] that facilities necessary to meet future growth can be financed by the utilities operating in this State on terms which are reasonable and fair to both the customers and existing investors of such utilities; . . . authoriz[ing] fixing of rates in such a manner as to result in lower costs of new facilities and lower rates over the operating lives of such new facilities by making provisions in the rate-making process for the investment of public utilities in plants under construction; encourage[ing] and promot[ing] harmony between public utilities, their users and the environment; . . . foster[ing] the continued service of public utilities on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety and for the promotion of the general welfare . . . seek[ing] to adjust the rate of growth of regulated energy supply facilities . . . cooperat[ing] with other states and with the federal government in promoting and coordinating interstate and intrastate public utility service and reliability of public utility energy supply; . . . and . . . promot[ing] the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that will [d]iversify the resources used to reliably meet the energy needs of consumers in the State. Provide greater energy security through the use of indigenous energy resources available within the State. Provide improved air quality and other benefits to energy consumers and citizens of the State.

§ 62-2 (effective Jan. 1, 2008).

15. *See* Hari M. Osofsky & Hannah J. Wiseman, *Hybrid Energy Governance*, 2014 U. ILL. L. REV. 1 (2014).

16. FERC, the North American Electric Reliability Corporation (NERC), and its subregions, and in some states, Regional Transmission Organizations or Independent System Operators also play important roles regarding reliability. *See id.* at 36-40; *About NERC*, NERC, http://www.nerc.com/AboutNERC/Pages/default.aspx (last visited Feb. 27, 2016); *Capacity Market (RPM)*, PJM, http://www.pjm.com/markets-and-operations/rpm.aspx (last visited Feb. 27, 2016) ("PJM's capacity market, called the Reliability Pricing Model, ensures long-term grid reliability by securing the appropriate amount of power supply resources needed to meet predicted energy demand in the future."); *Reliability Operating Procedures*, MISO, https://www.misoenergy.org/MarketsOperations/ReliabilityOperatingProcedures/

erning the economic aspects of electric utility regulation.[17] States typically delegate primary responsibility for other aspects of electric utility oversight, such as public health impacts, to other agencies. There are also notable differences among the states, chief among them the different scope of PUC authority in states following the traditional regulatory model versus the states that have restructured their electricity markets. Restructured states rely on competition among electricity generators to provide power and limit prices.[18] PUCs in restructured states do not, therefore, directly regulate generation investments.[19] These states maintain the monopoly structure for transmission and distribution services, with PUCs overseeing rates that distribution companies charge to consumers, the capital expenditures necessary to maintain the distribution system infrastructure, and any electricity procurement by the distribution company.[20]

The majority of states maintain the traditional regulatory model, with electric utilities operating as vertically integrated firms, controlling generation, transmission, and retail sales, and subject to rate regulation by the state utility commission.[21] Of all the agencies overseeing aspects of the electric power sector, the PUC in a traditionally regulated state is most directly involved in a regulated utility's decisions regarding how it meets electricity demand, including whether to build a new facility and, if so, what type.

This Article focuses on traditionally regulated states and draws upon representative proceedings to identify common approaches and notable differences in approaches to least cost planning. This Article does not attempt to provide a thorough examination of any particular state. The following subsections offer an overview of PUC decision-making, including the elements that utility commissions must balance when determining whether to allow utilities to recover expendi-

---

Pages/ReliabilityOperatingProcedures.aspx (last visited Feb. 27, 2016) (noting that the RTO "ensures real-time operating reliability of the interconnected bulk electric system . . . within the MISO reliability footprint").

17. Commissioners typically refer to themselves as economic regulators. David Hadley, Comm'r, Ind. Util. Regulatory Comm'n, The Commissioner's Challenge 3-4 (Oct. 4, 2004), http://www.gasification.org/uploads/eventLibrary/03HADL_Paper.pdf ("Today I am an economic regulator. Regulated utilities face folks like me all across the country with one thought – least cost. . . . There are many valid arguments about the cost of NOT being environmentally responsible. But as an economic regulator, I must approve of continually *increasing* cost of environmental compliance for coal fired power plants.").

18. *See* Peter Fox-Penner & Heidi Bishop, *Mission, Structure, and Governance in Future Electric Markets: Some Observations*, 89 OR. L. REV. 1107, 1109 (2011).

19. *See id.*

20. *See id.*

21. *Status of Electricity Restructuring by State*, U.S. ENERGY INFO. ADMIN. (Sept. 2010), http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html. Note that vertically integrated utilities also purchase and sell electricity in wholesale markets.

tures through rates charged to consumers and the least cost framework that PUCs in most states utilize to balance the competing interests of ratepayers, utilities, and their investors.

A. Cost-of-Service Rate Setting

The traditional state regulatory model for the electricity sector emerged based on the natural monopoly concept.[22] Due to the high cost of infrastructure, it was more efficient for a single firm to own and operate generation and transmission assets rather than allow competition through redundant infrastructure investments.[23] States relied on utility commissions to control the market power that results from the monopoly structure.[24] In exchange for an exclusive service territory, the utility is subject to rate regulation by the state PUC.[25]

PUCs set rates based on the cost of providing the service, including capital costs and operating costs.[26] In general, a commission must determine that a utility expenditure was prudently incurred before including that cost in the utility's "rate base."[27] Prudency may turn on a number of factors, including whether a utility asset is "used and useful" (i.e., it provides a service to customers).[28] Due to the challenge

---

22. *See* Boyd, *supra* note 12, at 1643-44.

23. *See id.*

24. *See, e.g.*, DIV. OF POLICY ANALYSIS & INTERGOVERNMENTAL LIAISON, FLA. PUB. SERV. COMM'N, MARKET POWER IN A TRANSITIONING ELECTRIC INDUSTRY 1 (2001), http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/markpwr.pdf.

25. KARL MCDERMOTT, EDISON ELEC. INST., COST OF SERVICE REGULATION IN THE INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY: A HISTORY OF ADAPTATION 5-8 (2012), http://www.eei.org/issuesandpolicy/stateregulation/Documents/COSR_history_final.pdf.

26. JONATHAN A. LESSER & LEONARDO R. GIACCHINO, FUNDAMENTALS OF ENERGY REGULATION 78-82 (2d ed. 2013).

> [T]he standard ratemaking formula: $R = O + (B\ x\ r)$, where R is the utility's allowed revenue requirement, O is its operating cost, B is rate base, and r is the utility's cost of capital. B increases as the utility's investment increases. O increases to the extent of the annual depreciation of the plant but decreases to the extent that the new plant permits a reduction in the use of plants with higher operating costs (principally fuel costs).

Richard J. Pierce, Jr., *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. PA. L. REV. 497, 511 (1984) (footnote omitted).

27. *See, e.g.*, COLO. CODE REGS. § 723-3, at 3617(d) (2015) (affording presumption of prudence for utility actions consistent with an approved resource plan); Pub. Serv. Co. of Colo., No. C13-0436 (Colo. Pub. Utils. Comm'n Mar. 21, 2013) (denying recovery of certain smart grid investments based on the utility's failure to demonstrate prudence).

28. *See, e.g.*, Potomac Elec. Power Co. v. Pub. Serv. Comm'n, 661 A.2d 131, 137-38 (D.C. 1995); El Paso Nat. Gas Co. v. Fed. Power Comm'n, 281 F.2d 567, 573 (5th Cir. 1960); Glustrom v. Colo. Pub. Utils. Comm'n, 280 P.3d 662, 669 (Colo. 2012) (noting that the "used and useful" test is "one of several permissible tools of ratemaking, one that need not be . . . employed in every instance" (quoting Jersey Cent. Power & Light Co. v. Fed. Energy Regulatory Comm'n, 810 F.2d 1168, 1175 (D.C. Cir. 1987))); North Carolina *ex rel.* Utils.

inherent in determining what qualifies as a prudent investment on the part of the regulated utility, commissions traditionally base prudency determinations on laws and other circumstances in existence at the time of the decision.[29] Commissions also set the rate of return that utilities earn for the capital expenditures included in the rate base and determine which variable costs, such as fuel and labor expenditures, utilities may recover from consumers.[30]

The rate-setting process grants broad discretion to commissions. The U.S. Supreme Court, and subsequently state courts, recognized that agencies with the delegated legislative power to set rates are not bound "to the service of any single formula or combination of formulas."[31] These agencies

> are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. Once a fair hearing has been given, proper findings made and other statutory requirements satisfied, the courts cannot intervene in the absence of a clear showing that the limits of due process have been overstepped.[32]

If the agency decision, "as applied to the facts before it and viewed in its entirety, produces no arbitrary result, [the Court's] inquiry is at

---

Comm'n v. Carolina Water Serv., Inc., 439 S.E.2d 127 (N.C. 1994); SCOTT HEMPLING, PRESIDE OR LEAD?: THE ATTRIBUTES AND ACTIONS OF EFFECTIVE REGULATORS 190-92 (2d ed. 2013) ("Courts have defined prudence circularly, as avoiding 'unreasonable costs,' operating at 'lowest feasible cost,' and 'operat[ing] with all reasonable economies.' " (alteration in original) (citing Gen. Tel. Co. of Upstate N.Y. v. Lundy, 218 N.E.2d 274, 277 (N.Y. 1966))).

29. *See, e.g.*, Ky. Power Co., No. 2009-00545 (Ky. Pub. Serv. Comm'n June 28, 2010) (denying Kentucky's application for approval of renewable energy purchase agreement for wind energy resources between); Appalachian Power Co., 263 P.U.R. 4th 297 (W. Va. Pub. Serv. Comm'n Mar. 6, 2008), 2008 WL 1758812 (order on the application for a certificate of public convenience & necessity for a 629 megawatt integrated gasification combined cycle generating facility in mason county; Appalachian Power Co., No. PUE-2007-00068 (Va. State Corp. Comm'n Apr. 14, 2008) (final order denying the application for approval of a rate adjustment clause under section 56-585.1 A 6 of the Code of Virginia).

30. *See* LESSER & GIACCHINO, *supra* note 26, at 78-82.

31. Fed. Power Comm'n v. Nat. Gas Pipeline Co., 315 U.S. 575, 586 (1942). States have generally adopted the *Federal Power Commission* holding for state PUCs. *See, e.g.*, S. Conn. Gas Co. v. Conn. Dep't of Pub. Util. Control, No. CV094021665S, 2010 WL 1664975, at *5 (Conn. Super. Ct. Apr. 1, 2010) (citing *Nat. Gas Pipeline Co.*, 315 U.S. at 586); City of Miami v. Fla. Pub. Serv. Comm'n, 208 So. 2d 249, 255-56 (Fla. 1968) (first quoting Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591 (1944); then citing *Nat. Gas Pipeline Co.*, 315 U.S. at 575); Ohio Edison Co. v. Pub. Utils. Comm'n, 589 N.E.2d 1292, 1298 (Ohio 1992) (first quoting *Hope Nat. Gas*, 320 U.S. at 591; then citing *Nat. Gas Pipeline Co.*, 315 U.S. at 575); *see also* George Blum et al., *Rates and RateMaking*, 73B C.J.S. *Public Utilities* § 26 (2015).

32. *Nat. Gas Pipeline Co.*, 315 U.S. at 586.

an end."[33] The PUC's discretion is subject to important limitations, however.[34] In addition to complying with all statutory mandates, the rates must allow utilities to recover costs that were prudently incurred, maintain the financial integrity of the firm, compensate equity investors for the risks they assume, and enable the firm to attract needed capital.[35] Rates may not be confiscatory, and commissions must balance the interests of consumers and investors.[36] In the end, rates set by the commission generally must satisfy the "just and reasonable" standard, which courts interpret to address both consumer and investor interests.[37]

---

33. *Id.* While not binding, commission precedent may still be persuasive, and reviewing courts may nonetheless look to commission precedent when evaluating whether a rate case is arbitrary and capricious. *See, e.g.*, Cont'l Tel. Co. of the S. v. Ala. Pub. Serv. Comm'n, 427 So. 2d 981, 993 (Ala. 1982) ("[W]hile *stare decisis* does not apply to decisions of administrative agencies such as the Commission, consistency is essential if arbitrariness is to be avoided.") (emphasis added); North Carolina *ex rel.* Utils. Comm'n v. Carolina Util. Customers Ass'n, 500 S.E.2d 693, 706 (N.C. 1998) ("[T]he final order of the [Utilities] Commission [in a general rate case] is not within the doctrine of *stare decisis* . . . prior decisions of [the Supreme Court] regarding general questions of law and the principles underlying those decisions serve to guide the Court's decisions in individual cases.") (third alteration in original) (citations omitted).

34. *See, e.g.*, LESSER & GIACCHINO, *supra* note 26, at 52-54.

35. *Hope Nat. Gas Co.*, 320 U.S. at 605; *see* Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 692 (1923).

36. *Hope Nat. Gas Co.*, 320 U.S. at 605. State courts and utility commissions follow *Hope Natural Gas*. *See, e.g.*, Glustrom v. Colo. Pub. Utils. Comm'n, 280 P.3d 662, 669 (Colo. 2012); *see also* S. Bell Tel. & Tel. Co. v. Miss. Pub. Serv. Comm'n, 113 So. 2d 622, 656 (Miss. 1959) ("A fair return is one which, under prudent and economical management, is just and reasonable to both the public and the utility. . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks and sufficient to assure confidence in the financial integrity of the business. What the public is entitled to demand is that no more should be exacted from the rate payers than the services are reasonably worth.").

37. The "just and reasonable" language has its roots in the Natural Gas Act. 15 U.S.C. § 717c (2012). State laws governing PUCs have generally adopted the same framework. *See, e.g.*, COLO. REV. STAT. § 40-3-101(1) (2015) (requiring utility rates to be "just and reasonable"); IDAHO CODE § 61-302 (2015) (requiring that "[e]very public utility shall furnish, provide and maintain such service, instrumentalities, equipment and facilities as shall promote the safety, health, comfort and convenience of its patrons, employees and the public, and as shall be in all respects adequate, efficient, just and reasonable"); MISS. CODE ANN. § 77-3-33(1) (2015) (stating that the public utility company is entitled to "fair, just and reasonable rates for the services rendered or to be rendered by it to any person"); N.C. GEN. STAT. § 62-130(a) (2014) (requiring the PUC to "make, fix, establish or allow just and reasonable rates for all public utilities subject to its jurisdiction"); WASH. REV. CODE § 80.28.020 (2014) (authorizing the commission to fix rates determined to be reasonable and just); WIS. STAT. § 196.03(1) (2015) (requiring rates to be reasonable and just). After the Supreme Court's decision in *Hope Natural Gas*, judicial inquiries now typically focus on whether the end result of the rate-setting process satisfies the just and reasonable standard and will not second-guess how the commission arrives at the rate. *See Hope Nat. Gas Co.*, 320 U.S. at 605.

Commissions typically have additional duties beyond rate-setting. For example, they may approve siting proposals[38] and, in some states, review long-term, integrated resource plans (IRPs) wherein utilities evaluate various scenarios to determine likely future resource needs.[39] PUCs may also have a range of duties related to environmental goals, including obligations related to state environmental policy compliance, implementation of renewable energy and energy efficiency mandates, and resource planning.[40]

B. The Least Cost Framework

PUCs seek an outcome that allows the utility to plan for the future, prevents electric utilities operating as monopolies from taking advantage of market power and charging unreasonably high rates, allows the utility to hedge various forms of risk without approving unnecessary expenditures, and allows returns on investment at a level that maintains the firm's creditworthiness. Viewed from a theoretical perspective, this effort to balance competing interests in pursuit of an affordable and reliable electricity sector is analogous to the utilitarian goal of maximizing societal welfare by promoting the greatest pleasure for the greatest number.[41] Thus, utilitarianism "perspectives" discourse provides an analytical approach for identifying and weighing multiple factors and seeking the optimal outcome. Moreover, the consequentialist utilitarian approach judges the merits of the action on the outcome (e.g., rates that are just and reasonable) rather than the methodology for determining the course of action (e.g., which factors were given more or less weight when setting the rates). In the PUC context, cost minimization coupled with reliability replace welfare maximization as the desired outcome. To protect against profit maximizing incentives, states typically employ a "least cost" framework for assessing whether a utility's investment is prudent.[42]

---

38. *See* Michael Dworkin et al., *Revisiting the Environmental Duties of Public Utility Commissions (2006)*, 7 VT. J. ENVTL. L. 1, 42 (2006).

39. *See, e.g.*, *U.S. States with Integrated Resource Planning or Similar Planning Process*, REG. ASSISTANCE PROJECT (2009), http://www.energycollection.us/Energy-Planning/US-States-IRP.pdf.

40. Dworkin et al., *supra* note 38, at 6; Michael Dworkin et al., *The Environmental Duties of Public Utility Commissions*, 18 PACE ENVTL. L. REV. 325, 331 (2001).

41. Proponents of utilitarianism offer various characterizations of the optimal outcomes. Bentham and Mill, early advocates of utilitarianism as a policymaking tool, suggested that the optimal outcome is one that maximizes pleasure and minimizes pain. *See* BENTHAM, *supra* note 8, at 3. For a detailed discussion of classic philosophic concepts of rights and duties applied to the energy sector, see BENJAMIN K. SOVACOOL & MICHAEL H. DWORKIN, GLOBAL ENERGY JUSTICE: PROBLEMS, PRINCIPLES, AND PRACTICES (2014).

42. Melissa Powers, *Sustainable Energy Subsidies*, 43 ENVTL. L. 211, 221 (2013).

This approach may appear as a statutory or regulatory obligation,[43] or PUCs themselves may introduce the concept as a factor in prudency determinations.[44]

The regulation of the natural monopoly seeks to maximize societal welfare by allowing the firm to operate without competition while preventing abuse of market power.[45] Thus, the characterization of PUC decision-making as a pursuit of the classic utilitarian goal of welfare maximization is descriptive rather than a normative argument for altering the regulatory approach. As previously described,[46] the PUC is charged with considering multiple factors when setting electricity rates. The different stakeholders affected by the outcome of a PUC decision—residential and commercial electricity consumers, industrial electricity consumers, utility shareholders, investors issuing debt to finance a utility's capital investments, elected officials, citizens affected by the environmental impacts of electricity generation, individuals and businesses that may benefit from low energy prices attracting additional economic development to a region, firms manufacturing electricity generation equipment—may have their own views of an optimal outcome depending on how it will affect their core interests. The shareholder seeks increasing share value and regular dividends. The industrial consumer seeks to maintain low electricity rates to reduce input costs. The financial institution issuing debt may prefer a larger capital expenditure to generate larger returns. State legislators and governors may seek to avoid sharp increases in electricity rates. Utility commissioners themselves are also interested stakeholders. Whether elected or appointed, commissioners operate in a political environment that may create a disincentive to approve rate increases.

---

43. *See, e.g.*, HAW. REV. STAT. § 226-18(c)(3), (5) (2013) (stating that the policy of the state shall "[e]nsure, to the extent that new supply-side resources are needed, that the development or expansion of energy systems uses the least-cost energy supply option and maximizes efficient technologies"); MONT. CODE ANN. §§ 69-3-1204(1) (2014) (requiring electric utilities to file a plan that meets customer needs in the most cost-effective manner); 170 IND. ADMIN. CODE 4-8-3 (2015) (requiring the PUC to "ensure [that] a utility's proposal is consistent with acquiring the least-cost mix of demand-side and supply-side resources to reliably meet the long-term electric service requirements of the utility's customers"); MONT. ADMIN. R. 38.5.2001-.2016 (2015) (defining guidelines for least cost planning for electric utilities).

44. *See, e.g.*, Ky. Power Co., No. 2009-00545 (Ky. Pub. Serv. Comm'n June 28, 2010). The least cost mandate may also appear as the "lowest reasonable costs." *See* Miss. Power Co., No. 2010UA279, 2012 WL 1484068, at *2 (Miss. Pub. Serv. Comm'n Apr. 3, 2012) (final certificate order).

45. *See, e.g.*, Jim Rossi, *Moving Public Law out of the Deference Trap in Regulated Industries*, 40 WAKE FOREST L. REV. 617, 623 (2005) ("For most of the twentieth century, cost-of-service regulation provided regulators a ready forum for ensuring that rates did not discriminate in ways that caused serious losses to social welfare.").

46. *See supra* Section II.A.

Both the utilitarian philosophers and the commissioners seeking to implement policy goals that are, at their core, utilitarian face criticism regarding the conceptualization of the optimal outcome and how the decision-maker assigns weights to various factors that inform the outcome. Critics of the utilitarian theory as a guide to personal behavior or policy choices point out that the theory fails to account for variability in preferences and is subjective regarding the number of variables to consider or what weight to give those variables.[47] Moreover, the theory depends on an accurate assessment of the consequences of a decision, despite the inherent difficulty projecting what those consequences may be.

PUC processes suffer from the same deficiencies. Although the focus on cost minimization rather than welfare maximization arguably provides a more objective standard, PUC cases turn on subjective assessments. For example, an inquiry focusing on a narrow range of near-term variables will likely produce a dramatically different outcome than one that weighs a broader range of variables and considers impacts over time.[48] In many states, the least cost mandate is general enough to allow either approach, but PUCs generally apply the mandate in a manner than limits the scope of costs taken into consideration to those associated with capital investments. As Part III demonstrates,[49] commissioners serving on the same PUC may assign different weight to variables such as certainty, nearness in time, fuel diversity, risk hedging, environmental impacts, and even interpretations of electricity demand growth projections. The outcome of those PUC decisions may turn as much on commissioners' value choices and views of the future as on objective assessments of cost and risk.

Proponents of a strict adherence to benefit-cost analysis may argue that the theoretical utilitarian argument is unnecessary, and instead might promote a more robust effort to quantify the potential results of a utility decision. There is a lengthy and ever expanding body of scholarship debating the merits and limits of a benefit-cost analysis.[50] Although the benefit-cost approach frames the discussion in contemporary regulatory language, it raises many of the same questions as the utilitarian inquiry—e.g., costs for whom, which ben-

---

47. *See, e.g.*, Richard A. Posner, *Utilitarianism, Economics, and Legal Theory*, 8 J. LEGAL STUD. 103, 111-19 (1979).

48. *See* 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).

49. *See infra* Part III.

50. For competing views of benefit-cost analysis, compare FRANK ACKERMAN & LISA HEINZERLING, PRICELESS: ON KNOWING THE PRICE OF EVERYTHING AND THE VALUE OF NOTHING (2004), with Richard A. Posner, *Cost-Benefit Analysis: Definition, Justification, and Comment on Conference Papers*, 29 J. LEGAL STUD. 1153 (2000).

efits to consider, and what methods are used to quantify the costs and impacts.[51] Benefit-cost analysis is particularly limited when dealing with "inherently political questions involving contested normative issues."[52]

Although this Article does not engage directly in the ongoing debate over the proper application of cost considerations in administrative proceedings, the debate is relevant for PUC decision-making. Cost impacts are at the heart of PUC inquiries, yet quantifying the potential impacts of electric utility actions is inherently subjective. As the following subsections demonstrate, commissioners choose among a range of reasonable viewpoints regarding the need for new generation and the factors to consider when evaluating whether an option is cost-effective, and those choices may lead to very different near-term and long-term impacts on electricity rates and environmental impacts of the electricity sector. This Article opts for the lens of classic utilitarian theory as a framework for examining the value choices inherent in the least cost inquiry and alternative approaches that may maximize societal benefits beyond simply near-term low rates for electricity. Rather than undermining the argument for viewing PUC decisions through the utility maximization lens, the discretion and embedded value choices argue for an explicit consideration of a wider range of variables.

1. *The Many Views of "Cost" in Electricity Sector Regulation*

Although the observation that utility regulation, as practiced in many states, is an exercise in utility maximization is descriptive, a normative argument follows. If, indeed, PUCs aim to maximize societal benefits, one must inquire whether they are achieving that goal given the wide-ranging economic, health, and environmental impacts that flow from PUC decisions.

---

51. *Compare* Daniel A. Farber, *Breaking Bad? The Uneasy Case for Regulatory Breakeven Analysis*, 102 CALIF. L. REV. 1469, 1469 (2014) (arguing that breakeven analysis "may fail to improve the rationality of decisions, especially in hard cases"), *with* Cass R. Sunstein, *The Limits of Quantification*, 102 CALIF. L. REV. 1369, 1392 (2014) (proposing use of "breakeven analysis" to "identify a lower or upper bound for regulatory benefits" in circumstances where quantification is challenging). *See also* Matthew D. Adler, *Beyond Efficiency and Procedure: A Welfarist Theory of Regulation*, 28 FLA. ST. U. L. REV. 241, 245 (2000) ("Two neoclassicists who agree as to the moral significance of efficiency, and as to the equivalence of welfare and preference satisfaction, may disagree about whether some further moral criterion (besides efficiency) is also relevant in evaluating regulatory choices, options, and institutions. One neoclassicist may think that the environment has intrinsic value, apart from human welfare; another may deny that. Or, one neoclassicist may think that the fair distribution of welfare, as well as Kaldor-Hicks efficiency, is an important thing; another neoclassicist may be solely concerned with efficiency.") (footnote omitted).

52. Jonathan S. Masur & Eric A. Posner, *Climate Regulation and the Limits of Cost-Benefit Analysis*, 99 CALIF. L. REV. 1557, 1557 (2011).

Utilities assess infrastructure needs and the associated costs through scenario analysis that considers variables such as fuel price fluctuation, policy changes, transmission needs, and technology options.[53]

Utility planning also includes qualitative variables, such as "the importance of fuel diversity, [a firm's] environmental profile, the emergence and development of new technologies, and regional economic development considerations."[54] Utilities, regional transmission organizations, and regulators seek to quantify benefits associated with the qualitative variables in order to justify the costs, but that process is challenging and ballpark estimates sometimes must suffice.[55] Both the qualitative and quantitative assessments rely on value choices regarding which variables to consider, how much weight to assign to different variables, and the scope of costs.

The broadest view of the costs associated with electricity generation would incorporate not just electricity rates, but also health costs resulting from pollutants emitted by the facilities, costs to the local economy if a power plant contributes to the area's nonattainment status for any National Ambient Air Quality Standard, the full suite of costs associated with climate change mitigation and adaptation, and externalities arising from the production and transport of the fuels.[56] From the beginning of public utility regulation, states have opted to separate the cost of service from numerous other costs associated with the production and consumption of electricity, relying on other government agencies to address those externalities. That separation does not absolve the PUC of all responsibility for the costs beyond electricity rates, however, as the initial decisions regarding

53. *See, e.g.*, DUKE ENERGY, THE DUKE ENERGY CAROLINAS INTEGRATED RESOURCE PLAN (ANNUAL REPORT) 7 (2012) [hereinafter DUKE ENERGY IRP 2012] ("Quantitative analysis provides insights on future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs, and other variables."); GA. POWER CO., 2013 INTEGRATED RESOURCE PLAN AND APPLICATION FOR DECERTIFICATION OF PLANT BRANCH UNITS 3 AND 4, PLANT MCMANUS UNITS 1 AND 2, PLANT KRAFT UNITS 1-4, PLANT YATES UNITS 1-5, PLANT BOULEVARD UNITS 2 AND 3 AND PLANT BOWEN UNIT 6, at 1-28, GA. PSC DOCUMENT FILING # 145981 (Jan. 31, 2013), http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=145981 (follow "Attachment: 145981.zip" hyperlink; then open "IRP MAIN DOC AND DECERT APP); TENN. VALLEY AUTH., INTEGRATED RESOURCE PLAN: TVA'S ENVIRONMENTAL & ENERGY FUTURE 61-77 (2011).

54. DUKE ENERGY IRP 2012, *supra* note 53.

55. *See, e.g.*, Ill. Commerce Comm'n v. Fed. Energy Regulatory Comm'n, 721 F.3d 764 (7th Cir. 2013).

56. The electricity sector is the primary emitter of mercury and sulfur dioxide in the United States and is a major contributor of emissions of nitrogen oxides—precursors to ground level ozone. *The 2011 National Emissions Inventory*, U.S. ENVTL. PROTECTION AGENCY, http://www.epa.gov/ttn/chief/net/2011inventory.html (last visited Feb. 27, 2016). In 2013, the sector was also responsible for 31% of U.S. greenhouse gas emissions. *Sources of Greenhouse Gas Emissions*, U.S. ENVTL. PROT. AGENCY, http://www3.epa.gov/climatechange/ghgemissions/sources.html (last visited Feb. 27, 2016).

what to build are the foundation for many of the other societal costs. In some circumstances, it may be less costly to society to avoid potentially large rate increases in the future by investing in higher cost generation options at the outset.[57]

Despite these impacts on public health and the environment, states diverge regarding the range of environmental and public health impacts that the commission may consider. Colorado law, for example, requires the PUC to "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, insulation from fuel price increases, and environmental protection."[58] In addition, the Colorado PUC "may give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire resources."[59] North Carolina's Public Utilities Act (NC PUA) offers an example of a less specific environmental obligation, instructing the state's commission to "encourage and promote harmony between public utilities, their users and the environment."[60] Legislatures in other states expressly prohibit PUCs from considering certain environmental impacts in the rate-setting process.[61] For example, North Dakota law prohibits the state's PUC from "us[ing], requir[ing] the use of, or allow[ing] electric utilities to use environmental externality values in the planning, selection, or acquisition of electric resources or the setting of rates for providing electric service."[62]

Legislation explicitly expanding the range of factors PUCs consider may foster consideration of a broader suite of public policy goals affected by electric utility decisions. However, in the absence of legis-

---

57. *See, e.g.*, Richard N. L. Andrews, *State Environmental Policy Innovations: North Carolina's Clean Smokestacks Act*, 43 ENVTL. L. 881 (2013); David Hoppock et al., *Benefits of Early State Action in Environmental Regulation of Electric Utilities: North Carolina's Clean Smokestacks Act* (Nicholas Inst. for Envtl. Policy Sols., Working Paper No. NI WP 12-05, 2012).

58. COLO. REV. STAT. § 40-2-123(1)(a) (2015).

59. *Id.* § 40-2-123(1)(b).

60. N.C. GEN. STAT. § 62-2(a)(5) (2014). Notably, the mission statement on the NC Utilities Commission website lists a broad range of PUC obligations found in the NC PUA's "Declaration of Policy" but neglects to mention the environmental provision. *See Welcome to the North Carolina Utilities Commission*, N.C. UTILS. COMM'N, http://www.ncuc.commerce.state.nc.us/ (last visited Feb. 27, 2016).

61. *See* Richard D. Gary & Michael L. Teague, *The Inclusion of Externalities in Electric Generation Resource Planning: Coal in the Crossfire*, 95 W. VA. L. REV. 839, 862-63 (1993).

62. 1995 N. D. Laws 1311.

lation specifically limiting the factors they may consider, PUCs can generally take steps within the least cost framework to pursue a range of societal objectives affected by the electricity sector. For example, although direct regulation of public health impacts may fall outside the regulatory purview of the utility commissioner, it does not follow that commissioners must turn a blind eye to the health impacts of their decisions.[63] PUC decisions affect the amount and types of emissions, and due to the costs locked in when constructing a new power plant, they also affect the economic impact of changing course.[64] The EPA's Mercury Air Toxics Rule (requiring reductions in mercury emissions) and the Cross State Air Pollution Rule (CSAPR) (limiting sulfur dioxide (SO2), nitrogen oxides (NOx), and particulate matter (PM) emissions originating at coal-fired power plants in upwind states and affecting a downwind state's compliance with air quality standards) offer cautionary tales regarding the risk of ignoring the prospect of more stringent environmental regulations. Both rules affected the cost of existing coal-fired power plants, with the impacts differing by state based on the number of coal-fired power plants that did not meet the new standards. The states with less reliance on uncontrolled coal-fired power plants were less affected by new EPA regulations.[65] Ignoring the prospect of higher costs over the lifetime of a facility may subject consumers to higher prices while also robbing them of the benefits of early action.[66] Therefore, viewing environmental issues through the lens of potential increases in operating costs over the lifetime of a power plant should allow commissioners to consider impacts on public health and the environment under existing least cost framework unless explicitly prohibited by state law from doing so.[67]

---

63. *See, e.g.*, North Carolina *ex rel.* Utils. Comm'n v. High Rock Lake Ass'n, 245 S.E.2d 787, 790 (N.C. Ct. App. 1978) (finding that environmental considerations are "generally left to other regulatory agencies, except as they affect the cost and efficiency of the proposed generating facility"). This Article is not proposing to burden PUCs with the primary responsibility of mitigating climate change. Such a broad problem requires attention from a range of state and federal agencies.

64. Patrick Bean & David Hoppock, *Least-Risk Planning for Electric Utilities* 3 n.2 (Nicholas Inst. for Envtl. Policy Sols, Working Paper No. NI WP13-05, 2013) ("Electricity sector capital investments tend to have low salvage values, meaning most costs are sunk and unrecoverable if the investment does not operate as planned.").

65. The North Carolina Clean Smokestacks Act is an example of a state taking action to reduce SO2, NOx, and mercury before the promulgation of Utility MATS and CSAPR, resulting in lower costs. Clean Smokestacks Act, 2002 N.C. Sess. Laws. 4 (codified as amended at N.C. GEN. STAT. §§ 62-143, 143-215.105-.114C (2014)). *See generally* Andrews, *supra* note 57; Hoppock et al., *supra* note 57.

66. *See* Hoppock et al., *supra* note 57, at 16.

67. *See, e.g.*, 1995 N. D. Laws 1311 (prohibiting the PUC from considering environmental externalities).

Uncertainty about the future complicates the cost minimization challenge, and utilities and PUCs may compensate by assuming perfect foresight when inputting assumptions into energy models.[68] The resulting projections may fail to consider the potential cost impacts of changing circumstances and also may undervalue non-cost factors. As a result, the traditional application of the least cost framework may undermine the goal of minimizing cost in the long term, as policy shifts to force electric utilities to internalize environmental externalities or as consumers bear costs in other ways such as medical bills.[69]

Achieving the least cost goal during the next one to two decades, and avoiding stranded generation assets resulting from changing economic and regulatory factors, is particularly complex due to the increased level of uncertainty regarding technology, markets, and regulation. Expanding the variables embedded in the least cost assessment could allow regulators to incorporate temporal considerations (e.g., short-term versus long-term "least cost" approaches), potential technological advances affecting demand or driving costs down if new technology can achieve market penetration, and public health and environmental impacts of electricity sector actions.

2. Assessing the Least Cost Option

Under the least cost framework, the optimal choice is the least cost investment after accounting for other factors such as reliability, state renewable energy or energy efficiency mandates, other legal

---

68. Perfect foresight in the modeling context refers to modeling exercises that assume scenarios remain constant throughout the period in question. For example, a scenario assuming high natural gas prices would maintain that assumption for each year included in the modeling exercise. The results produced by this approach may differ significantly from an exercise that tests the impacts of periodic fluctuations in fuel prices. *Compare*, NW. POWER & CONSERVATION COUNCIL, SIXTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN (2010) (utilizing an iterative modeling process with fuel price fluctuations), *with* U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2015 WITH PROJECTIONS TO 2040 (2015), http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf (analyzing numerous scenarios using a perfect foresight approach for each scenario).

69. *See, e.g.*, HEALTH & ENVTL. IMPACTS DIV., U.S. ENVTL. PROT. AGENCY, EPA-452/R-1-11-011, REGULATORY IMPACT ANALYSIS FOR THE FINAL MERCURY AND AIR TOXICS STANDARDS, at ES-3 (2011), http://www.epa.gov/ttnecas1/regdata/RIAs/matsriafinal.pdf (stating that emissions reductions under the final MATS rule could yield health co-benefits of up to $90 billion dollars in 2016, based on the avoidance of mercury- or fine particle-related health problems such as: 4200 to 11,000 premature deaths, 2600 hospitalizations for respiratory and cardiovascular diseases, 4700 nonfatal heart attacks, and 3.2 million missed work days due to respiratory symptoms); JOHN A. ROMLEY ET AL., THE IMPACT OF AIR QUALITY ON HOSPITAL SPENDING xi-xii tbl.S.2 (2010), http://www.rand.org/content/dam/rand/pubs/technical_reports/2010/RAND_TR777.pdf (explaining that not meeting federal clean air standards for PM2.5 and ozone caused an estimated 29,808 health events, resulting in an estimated $193 million spent on hospital care in California from 2005–2007).

obligations, and a range of risk factors. The electricity sector is not static, however. New information, changing market conditions, more stringent regulations, and emerging technologies can all alter the calculus.[70] There may be compelling reasons, therefore, to invest in a more expensive option in the near-term to hedge against potential increases in operating costs and capital expenditures in the future.

Many large-scale capital investments for new electricity generation assume power plants will operate for a minimum of three to four decades.[71] Investors are entitled to recoup capital investments and earn a rate of return on those investments once a PUC determines that the expenditures were prudent and approves incorporating the expenditures into the utility's rate base.[72] Circumstances may change dramatically during a plant's service life, potentially resulting in additional capital expenditures to comply with new regulations, fluctuation in operating costs due to fuel price volatility, and competition from newer facilities utilizing more efficient technologies.[73]

Hedging against the risk of costly future regulatory developments (e.g., regulation of a new pollutant or tightening existing emission limitations) presents a particularly challenging proposition for PUCs. Approving an electric utility investment in anticipation of a regulatory change that never materializes would result in consumers paying higher rates than required by existing law. Conversely, ignoring the prospect of increased costs due to future emission limits may cause a generating facility to face early retirement or additional costs to comply with the new regulations—costs that recent examples demonstrate could exceed $1 billion for an individual facility.[74] Distinguishing between legitimate hedging and efforts aimed at simply maximizing investors' returns, therefore, is an important, yet difficult, task for the utility commissioner.

Consider the scenario where a regulated monopoly determines that it must construct a 500-megawatt (MW) power plant to meet electricity demand. The firm is considering either a $500 million conventional natural gas combined cycle plant or a $3.5 billion coal-fired

70. *See, e.g.*, Pierce, *supra* note 26 (discussing the impact of changing circumstances on nuclear power plant construction).

71. *Age of Electric Power Generators Varies Widely*, U.S. ENERGY INFO. ADMIN. (JUNE 16, 2011), http://www.eia.gov/todayinenergy/detail.cfm?id=1830 (noting that 51% of the U.S. electric generating capacity was at least 30 years old at the end of 2010).

72. *See, e.g.*, Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923).

73. *See, e.g.*, STAN KAPLAN, CONG. RESEARCH SERV., RL34746, POWER PLANTS: CHARACTERISTICS AND COSTS 24 (2008) (noting that "fuel prices have been notoriously difficult to predict"); Pierce, *supra* note 26, at 509-10. For more discussion of uncertainty and irreversibility in the electricity sector, see *infra* Section III.B.

74. Hoppock et al., *supra* note 57, at 17.

gasification plant that captures CO_2 emissions.[75] The rate structure would allow the firm's shareholders to receive seven times the return on the coal-fired investment. Assuming each option would result in the same rate of return and a PUC determination of prudency would ensure the ability to recover all capital costs, the rational economic actor would seek to maximize value for shareholders and investors.[76]

To protect against profit maximizing incentives, commissioners typically employ a "constrained least cost" framework to assess whether an investment is prudent. Under this framework, the optimal choice is the least cost investment after accounting for other factors, such as grid reliability, state and federal laws, existing infrastructure, and fuel price projections. These non-cost objectives act as constraints on a cost minimization goal. Some non-cost variables are more straightforward to assess than others. State laws may change the least cost calculus by requiring utilities and PUCs to consider environmental externalities when evaluating the potential options, or mandating renewable energy and energy efficiency investments through portfolio standards.[77] Others are more difficult to quantify, such as uncertainty regarding fuel prices and future regulations.

Some states have deliberately moved away from a narrow "least cost" approach. The California Public Utilities Commission, for example, opted for a "least cost, best fit" analysis that recognizes there may be generation options, such as renewable energy, that are more costly but offer additional benefits.[78] In other states, departing from a strict adherence to a "least cost" approach would require statutory or regulatory changes, yet even a narrow interpretation of least cost invites consideration of factors that affect near-term and long-term electricity rates.

---

75. These estimates are based on the U.S. Energy Information Administration's (EIA) 2013 capital cost estimates for new power plants. U.S. ENERGY INFO. ADMIN., UPDATED CAPITAL COST ESTIMATES FOR UTILITY SCALE ELECTRICITY GENERATING PLANTS (2013), http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf. According to the EIA estimates, the average overnight capital cost for a conventional natural gas combined cycle (NGCC) plant a $917 per kilowatt hour (KWh). *Id.* at 6. Using these assumptions, the cost for a 500 MW plant would be $458.5 million. The estimate for a single unit coal-fired integrated gasification combined cycle (IGCC), such as the new plant under construction in Kemper County, Mississippi, is $6599 per KWh, or $3.29 billion. *Id.* The cost estimates are not directly analogous because the estimated nominal capacities for the two plants differ (620 MW for the NGCC unit and 520 MW for the IGCC unit). *Id.*

76. *See* Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052, 1068 (1962); Boyd, *supra* note 12, at 1651-58.

77. *See, e.g.*, DUKE ENERGY IRP 2012, *supra* note 53 (discussing quantitative and qualitative analysis of system planning options).

78. Jeff Guldner & Meghan Grabel, *Dealing with Change: The Long-Term Challenge for the Electric Industry*, NAT. RESOURCES & ENV'T 3, 6 (2008).

Utility commissions may approve a more expensive electricity generation option if it offers additional benefits such as diversity in the fuel mix or long-term price certainty. Commissions may also allow utilities to reduce exposure to regulatory risk, although, as noted above, PUCs may find these risks difficult to assess.[79] Under the example in the previous paragraph, if a regulated firm justifies the $3.5 billion option solely on the likelihood of a future environmental regulation and the regulation is never implemented, shareholders would reap large returns while consumers would pay higher rates to mitigate a risk that never materializes.

As the IGCC example demonstrates, the stakes are high. Decisions regarding whether to construct new power plants and, if so, what types of power plants to build and when to build them have broad impacts on electricity rates, local economies, and public health. New, large-scale power plants are major investments, and utilities generally expect to operate a plant for decades to recover costs.[80] Under normal circumstances, ratepayers must compensate the utility even if changing circumstances result in higher than anticipated costs. PUCs are generally prohibited from retroactive rate-setting.[81] This provides a high degree of certainty to the utility and its investors once a capital expenditure is included in the utility's rate base, transferring investment risk to ratepayers who will compensate the utility for its investment through a rate-of-return established by the PUC.

III. THE LEAST COST MANDATE AND THE CHANGING ELECTRICITY LANDSCAPE

A. The Least Cost Mandate in Action

The following subsections explore differing approaches to the least cost mandate in states that have not directly altered the factors

79. Other agencies at the federal or state levels may take action to incentivize or require innovation in the electricity sector. This point refers to specifically to the view of the PUC.

80. *See, e.g.*, *Age and Capacity of Operating US Coal and Gas Fired Generators, Fall 2011*, ROCKY MOUNTAIN INST., http://www.rmi.org/RFGraph-age_capacity_operating_US_coal_gas_generators (last visited Feb. 27, 2016); *Age of Electric Power Generators Varies Widely*, U.S. ENERGY INFO. ADMIN. (June 16, 2011), http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

81. *See, e.g.*, La. Power & Light Co. v. La. Pub. Serv. Comm'n, 523 So. 2d 850, 857 (La. 1988) ("Pervading the utility rate-making process is the fundamental rule that rates are exclusively prospective in application and that future rates may not be designed to recoup past losses."); *In re* Application of Columbus S. Power Co., 947 N.E.2d 655, 660 (Ohio 2011) (finding that the Ohio PUC violated both the state law and state constitution when it approved rates that allowed a regulated utility to "recoup[] losses due to past regulatory delay"); Portland Gen. Elec. Co., 86 P.U.R. 4th 463, 479 (Or. Pub. Utils. Comm'n 1987).

commissioners must address. Each case study offers competing views of the appropriate outcome. Three of the examples—Kentucky Power, Mississippi Power Company, and Duke Energy—include dissenting opinions that articulate reasonable alternative decision-making approaches. The fourth example—Appalachian Power Company—focuses on a project that required approval by PSCs in Virginia and West Virginia, but only received partial approval from one and was rejected by the other. In addition to sharing the common element of written opinions differing from one another, the cases also include projects that promised environmental benefits and occurred either before or at the early stage of the shale gas boom when it was uncertain whether the dramatic drop in natural gas prices would persist. Together, the examples illustrate how PUCs weigh competing variables, including cost impacts, reliability, fuel diversity, regulatory risk, and environmental impacts.

1. *Kentucky Power Example: Rejection of a Wind Energy Power Purchase Agreement*

A 2010 case before the Kentucky Public Service Commission (PSC) provides perhaps the best example of the least cost mandate in action, as the case involved a relatively inexpensive power purchase agreement (PPA) for wind energy that offered the potential to hedge against potential federal and state regulatory developments that seemed likely in the near future. Despite the fact that the proposed PPA would result in a rate increase of less than $1 per month for the average residential consumer, the PPA faced opposition from the state's attorney general and ultimately was denied by the state's PSC.

Kentucky Power, a subsidiary of American Electric Power that serves 170,000 customers in the western part of the state[82] sought approval from the PSC to charge consumers an additional $14 million to cover the cost of a long-term PPA for 100 megawatts (MW) of electricity produced at a wind energy facility.[83] The utility justified its request based on the Governor's proposal to implement a renewable energy standard that would require increasing amounts of renewable energy as a percentage of sales, legislation introduced in the state's General Assembly to mandate the use of renewable energy resources for generating electricity, and the enactment of renewable energy mandates in neighboring states. Kentucky Power argued that although there was no renewable energy mandate in Kentucky, "once

82. *Regulated Utility Operations*, AM. ELECTRIC POWER, http://www.aep.com/about/MajorBusinesses/RegulatedUtilityOperations.aspx (last visited Feb. 27, 2016).

83. Ky. Power Co., No. 2009-00545, at 1, 3 (Ky. Pub. Serv. Comm'n June 28, 2010).

such a standard is enacted, the increased demand for renewable generation will cause the prices for renewable energy to increase, making the pending wind power contract even more economically beneficial."[84] The new contract would cost an estimated $14.3–$14.5 million per year, resulting in an increase of $0.71 per month for the average residential consumer.[85] In essence, Kentucky Power was proposing to hedge business risk by entering into a long-term contract to provide wind energy at a stable, competitive price.

The Kentucky Attorney General intervened in the PSC proceeding and made the following arguments in opposition to the contract:

> First . . . there is currently no federal or state renewable energy requirement and . . . the purchase of wind power is thus a discretionary expense that residential customers and industrial manufacturers cannot afford at this time. Second, . . . Kentucky Power has no need for the energy expected to be provided by the Wind Contract because Kentucky Power is energy long and the wind purchase would only exacerbate that situation. . . . Third, . . . the Wind Contract is not economic on a net present value basis.[86]

The Attorney General also argued that the wind project was unlikely to produce as much electricity as Kentucky Power assumed and that delaying the investment was prudent because improvements in wind turbine technology would likely result in lower costs in the future.[87]

The PSC denied Kentucky Power's request, agreeing with the Attorney General that the utility did not have an immediate need for additional generation and "the proposed 20-year wind power contract has not been shown to be least-cost compared to Kentucky Power's available energy sources."[88] The PSC concluded that "[i]n the absence of legislative certainty regarding future renewable mandates, the value of the proposed wind power contract is speculative. There is no mandate at this time for utilities in Kentucky to supply renewable energy."[89]

The PSC Vice Chairman dissented, arguing that the contract was in fact competitive, pointing out that the price Kentucky Power currently pays for purchased power is approximately $45/MWh, which is nearly $2 more per MWh than the proposed wind contract price of

84. *Id.* at 2-3.
85. *Id.* at 3.
86. *Id.*
87. *See id.* at 4.
88. *Id.* at 6.
89. *Id.* at 7.

\$43/MWh.[90] Additionally, the dissent argued that the utility needed to enter into the PPA due to the "great pressures nationally and in Kentucky to increase renewables. . . . As a Commissioner, I am concerned that ratepayers in a state like Kentucky with no nuclear power, and little potential for in-state renewables . . . will be facing large rate increases."[91] Kentucky Power's "modest proposal would have guaranteed a price for 20 years for at least a small portion of Kentucky Power's generation mix and thus I believe it is in fact needed."[92] Furthermore, with the federal wind energy tax credit set to expire, the dissent argued, "[I]t is unlikely that future solicitations will generate bids as low as this one. Thus, for all of the above-stated reasons, I believe that this contract satisfies Kentucky's least-cost principles."[93]

The Kentucky Power case highlights the central role that near-terms cost impacts play in PUC proceedings, as well as the reluctance on the part of commissioners and consumer advocates[94] to accept utility arguments for investments that may hedge against uncertainty and risk but result in higher rates for consumers. In hindsight, there are two ways of viewing the decision. From one perspective, subsequent developments have validated the PSC majority and the Attorney General. As of the time of the publication date for this Article, there is no renewable energy mandate in the state, the PSC has approved rate increases for Kentucky Power consumers even without the proposed wind energy contract,[95]

---

90. *Id.* at 9 (Gardner, Comm'r, dissenting).

91. *Id.* at 10.

92. *Id.*

93. *Id.*

94. *Id.* at 1 (showing that the Kentucky Attorney General and the trade group Kentucky Industrial Utility Consumers, Inc. intervened to advocate the interests of Kentucky Power's consumers).

95. Ronn Robinson, *Kentucky Power Files to Withdraw Rate Case*, AEP KY. POWER (Nov. 22, 2013), https://www.kentuckypower.com/info/news/viewRelease.aspx?releaseID=1471 (showing an additional five percent rate increase beginning Jan. 1, 2014); Ronn Robinson, *Public Service Commission Approves Kentucky Power Rate Case Settlement Agreement*, AEP KY. POWER (June 28, 2010), https://www.kentuckypower.com/info/news/viewRelease.aspx?releaseID=872 (noting that the Kentucky PSC approved a 16.84% rate increase for Kentucky Power in 2010).

and Congress did not enact a federal cap-and-trade bill that would have required electricity generators to acquire emission allowances for each ton of CO_2 emitted during a year.[96] Furthermore, the cost of wind turbines continues to fall.[97]

The positions of the electric utility and the dissenting commissioner, however, argue that state law does not prohibit reasonable attempts to hedge risks. *Post hoc* evaluations may help refine the scope of the "least cost" framework, but the failure of risks to materialize within a few years should not present a barrier to expanding the temporal scope of the least cost inquiry, nor should it prohibit consideration of regulatory risk. As a business investing in infrastructure that will operate for multiple decades, the ability to hedge reasonably foreseeable risks, including fuel price volatility, regulatory uncertainty, and technology uncertainty may be critical to achieve the interrelated goals of affordable, reliable, and clean electricity. This view is bolstered by PUC decisions in a neighboring state. The same year that the Kentucky PSC denied Kentucky Power's request, the Indiana Utility Regulatory Commission approved a new wind energy PPA, noting the "real benefits for [the utility], its customers, and the State of Indiana."[98] Those benefits included "diversif[ying] [the] supply portfolio[,] . . . provid[ing] environmental benefits[,] . . . encourag[ing] the proliferation of [in-state renewable energy,] improv[ing the state's] economy[,] and . . . hedg[ing] against new environmental emissions regulations and potential fuel cost volatility."[99] A subsequent decision by the Kentucky PSC endorsed a similar ap-

96. The climate policy argument did not appear in the *Kentucky Power Co.* case, but the PSC considered the issue in a similar wind energy proceeding involving the regulated utilities Louisville Gas & Electric and Kentucky Utilities. Motion of Louisville Gas & Electric Co. & Kentucky Utilities Co. for a Declaratory ruling or, in the Alternative, for Waiver of Certain Filing Requirements at 4 n.3, Louisville Gas & Elec. Co. & Ky. Utils. Co., No. 2009-00353 (Ky. Pub. Serv. Comm'n Aug. 28, 2009) (citing federal legislative proposals to limit CO2 emissions among the justifications for approval to charge consumers for a power purchase agreement for wind energy without a full PSC hearing). Ultimately, the PSC denied the waiver request to permit the utilities to recover the cost of a wind energy power purchase agreement without a formal PSC proceeding. Order at 8, Louisville Gas & Elec. Co. & Ky. Utils. Co., No. 2009-00353 (Ky. Pub. Serv. Comm'n Oct. 21, 2009).

97. *See, e.g.*, Diane Cardwell, *Solar and Wind Energy Start to Win on Price vs. Conventional Fuels*, N.Y. TIMES (Nov. 23, 2014), http://www.nytimes.com/2014/11/24/business/energy-environment/solar-and-wind-energy-start-to-win-on-price-vs-conventional-fuels.html?_r=0 (referring to "recent analyses [that] show that even without those subsidies, alternative energies can often compete with traditional sources").

98. Ind. Mich. Power Co., No. 43750, 2010 WL 127594 (Ind. Util. Reg. Comm'n Jan. 6, 2010) (citing So. Ind. Gas & Elec. Co., No. 43635, at 8-10 (Ind. Util. Regulatory Comm'n June 17, 2009)); Indianapolis Power & Light Co., No. 43485 (Ind. Util. Regulatory Comm'n Oct. 1, 2008); Ind. Mich. Power Co., No. 43328 (Ind. Util. Regulatory Comm'n Nov. 28, 2007).

99. *Ind. Mich. Power*, 2010 WL 127594 (second alteration in original) (citation omitted).

proach to the costs and benefits associated with renewable energy when it departed from its strict adherence to the least cost analysis in a case involving a new biomass-fired electricity generating unit.[100] Noting the benefits of innovative energy projects to the local economy, the state's renewable energy goals that included biomass, and the project's ability to replace a portion of electricity from a retiring coal-fired power plant, the PSC approved the project.[101]

2. *Duke Energy Example: Approval of a New Coal-Fired Power Plant*

In 2007, the North Carolina Utilities Commission (NCUC) considered a proposal by Duke Energy Carolinas to construct two new 800 MW coal-fired units at its existing Cliffside Steam Station near Charlotte, North Carolina.[102] After testing a number of scenarios through its long-range resource planning, Duke Energy had determined that the new coal-fired units were the best option for meeting baseload electricity demand.[103] The utility reached this conclusion despite current factors suggesting the likelihood that the new facility would face limitations on greenhouse gas emissions through federal climate legislation or through regulations issued pursuant to the existing Clean Air Act.[104] The planning process examined six scenarios that included

---

100. *Kentucky Sidesteps Least-Cost Principles to Approve New PPA*, 4143 PUR UTIL. REG. NEWS 1 (Oct. 25, 2013).

101. Ky. Power Co., No. 2013-00144 (Ky. Pub. Serv. Comm'n Oct. 10, 2013).

102. Duke Energy Carolinas, LLC, 257 P.U.R. 4th 115 (N.C. Util. Comm'n Mar. 21, 2007), 2007 WL 1040917.

103. *Id.*

104. In 2007, the U.S. Senate was debating the Lieberman-Warner Climate Security Act that, if enacted, would have created a descending cap on greenhouse gas emissions from the power sector, transportation sector, and industrial sector. S. 2191, 110th Cong. (2007). The same year, the U.S. Supreme Court ruled that greenhouse gas emissions met the definition of "pollutant" under the Clean Air Act, thereby requiring the U.S. EPA to determine whether the pollutants emitted from motor vehicles endangered public health and welfare. Massachusetts v. EPA, 549 U.S. 497, 528-29 (2007). The EPA subsequently made such a finding, resulting in regulations not only limiting CO2 emission limits from motor vehicles, but also from the power sector and other stationary sources. *See, e.g.*, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009) (codified at 40 C.F.R. ch. 1 (2015)); 40 C.F.R. pts. 85, 86, 600 (2015) (originally published as 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards, 77 Fed. Reg. 62,624 (Oct. 15, 2012)); 40 C.F.R. pts. 51, 52, 70, 71 (2015) (originally published as Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010)); 40 C.F.R. pts. 85, 86 (2015); 49 C.F.R. pts. 523, 531, 533, 536, 537 (2015) (originally published as 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards, 77 Fed. Reg. 62,624 (Oct. 15, 2012)); Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662 (Oct. 23, 2015) (to be codified at 40 C.F.R. pt. 60); Standards of Performance for Greenhouse Gas Emissions

varying amounts of new coal, natural gas, nuclear, and renewable generation. The NCUC considered various alternatives for meeting some or all of the projected near-term demand needs, including investments in energy efficiency, renewable energy, and an integrated gasification combined cycle (IGCC) plant.[105] Energy efficiency and renewable energy were seen as ineffective in meeting the level of projected demand growth, and the IGCC technology was considered risky, too time-intensive, and more costly than the pulverized coal option.[106]

The commission approved one of the two proposed 800 MW units. The NCUC's decision turned primarily on two factors: (1) the perceived need for additional baseload generation by 2011 and (2) concerns about overreliance on natural gas and the fact that at the time natural gas was not used to provide baseload power.[107] The dissent argued that coal was not a prudent option for new generation, citing the provision in the NC Public Utilities Act requiring the commission to "encourage and promote harmony between public utilities, their users and the environment."[108] This provision, the dissent claimed, is not subservient to other NCUC duties.[109]

The NCUC decision prioritizes timing and fuel mix diversity over environmental considerations. Although the dissent did not persuade the commission that it must give equal weight to environmental considerations, the language in the Public Utilities Act arguably would allow commissioners to more fully incorporate potential environmental impacts into the NCUC decision-making process. Even without reliance on that provision, decisions regarding coal-fired power plants in other states demonstrate that commissions can reasonably consider environmental impacts and give more weight to alternative forms of energy. Commissions in Florida, Oklahoma, and Oregon rejected utility plans to build new coal-fired power plants due to concerns about future climate policy compliance costs and failures to adequately consider alternative energy options.[110]

---

from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510 (Oct. 23, 2015) (to be codified at 40 C.F.R. pts. 60, 70, 71, 98).

105. *Duke Energy Carolinas*, 2007 WL 1040917. An IGCC facility converts coal into a synthetic gas before generating electricity via a gas turbine and a steam turbine. *See How IGCC Works,* DUKE ENERGY, http://www.duke-energy.com/about-us/how-igcc-works.asp (last visited Feb. 27, 2016).

106. *Duke Energy Carolinas*, 2007 WL 1040917.

107. *Id.*

108. Public Utilities Act, N.C. GEN. STAT. § 62-2(5) (2014); *accord Duke Energy Carolinas*, 2007 WL 1040917 (Owens, Jr., Comm'r, dissenting).

109. *Duke Energy Carolinas*, 2007 WL 1040917.

110. *See* Fla. Power & Light Co., No. 070098-EI, at 4 (Fla. Pub. Serv. Comm'n July 2, 2007), http://www.psc.state.fl.us/library/filings/07/05350-07/07-0557.ord.doc (finding that

The Cliffside decision[111] demonstrates the limitations of modeling and the importance of a robust assessment of options. In addition to the congressional debate over federal climate policy that was underway at the time of the NCUC's Cliffside decision, the rapid change in circumstances following the decision calls into question the wisdom of approving a $1.8 billion[112] facility expected to operate for 40 years or more with known public health impacts and uncertain regulatory risks. Only four years after the decision, and one year before the new Cliffside unit became operational, Duke Energy was relying on natural gas units as baseload power, and energy projects suggest that natural gas prices will remain relatively stable for the foreseeable future.[113] And only seven years after the Cliffside decision, Duke Energy raised concerns about the proposed Clean Power Plan limiting carbon dioxide emissions from existing power plants pursuant to section 111(d) of the Clean Air Act because it would cause "many [electricity generating unit] owners and operators to abandon or significantly curtail operation of generating units where significant investments have been made to install state-of-the-art control systems to meet MATS and other air regulations."[114] The concerns about the proposed rule creating stranded assets demonstrates the circular reasoning that may result from a narrow view of the least cost framework—investment decisions that fail to adequately account for reasonably foreseeable changes in air quality regulations may lock in higher emissions, thereby exacerbating air quality issues that result in regulatory changes while also making the regulatory changes more expensive than they may have been otherwise. As Duke Energy notes in its comments, costs associated with stranded assets "are typically

the proposed coal-fired power plant was not the least cost resource due to future costs associated with CO2 emissions); Okla. Gas & Elec. Co., No. PUD 200800059 (Okla. Corp. Comm'n June 9, 2008); Pacificorp, Order No. 07-018 (Ore. Pub. Util. Comm'n Jan. 16, 2007), http://apps.puc.state.or.us/orders/2007ords/07-018.pdf. For more detail on these and other examples of state and local agencies rejecting coal-fired power plants, see Patrick Parenteau, *Lead, Follow, or Get Out of the Way: The States Tackle Climate Change with Little Help from Washington*, 40 CONN. L. REV. 1453, 1462-63 (2008).

111. *Duke Energy Carolinas*, 2007 WL 1040917.

112. *Project Overview*, DUKE ENERGY, http://www.duke-energy.com/about-us/cliffside-overview.asp (last visited Feb. 27, 2016).

113. DUKE ENERGY IRP 2012, *supra* note 55, at 7-10; *Environmental Performance Metrics,* DUKE ENERGY, http://sustainabilityreport.duke-energy.com/2011/environmental-footprint/environmental-performance-metrics/ (last visited Feb. 27, 2016) (showing in the Table titled "Fuels Consumed for U.S. Electric Generation" that in 2011 coal consumption decreased while natural gas consumption increased).

114. Duke Energy, Comments on the Proposed Rule on Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, at 197 (Dec. 1, 2014), http://www.ieca-us.com/wp-content/uploads/Duke-Energy-Comments_12.01.14.pdf.

borne by customers in accordance with rates approved by state regulatory commissions," a particular concern for the NCUC.[115]

3. *Mississippi Power Example: Approval of Retrofitting Existing Coal-Fired Units to Comply with New Environmental Regulations*

The federal Mercury and Air Toxics Standard (Utility MATS), promulgated December 2011 pursuant to section 112 of the Clean Air Act,[116] forced many utilities operating older coal-fired power plants to decide whether to undertake large capital investments to bring existing coal units into compliance with the Act or to retire the facilities and replace generation needs with natural gas.[117] In 2012, the Mississippi PSC faced this circumstance when it considered Mississippi Power's proposed $660 million retrofit at the Victor J. Daniel Electric Generating Facility ("Plant Daniel") in Jackson County, Mississippi.[118] Plant Daniel consists of "two coal units (Units 1 and 2) that combined are capable of generating approximately 1,020 MW (net summer peak) of electricity, and two natural gas-fired combined cycle units (Units 3 and 4) that combined are capable of generating approximately 1,054 MW (net summer peak) of electricity."[119] The PSC inquiry focused on Units 1 and 2, the newest units in Mississippi Power's fleet at the time.[120]

Mississippi Power acknowledged that additional environmental regulations were forthcoming, and those regulations would affect the

115. *Id.*

116. 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, 77 Fed. Reg. 9304, 9304 (Feb. 16, 2012) (codified at 40 C.F.R. pts. 60, 63 (2015)) [hereinafter Utility MATS]. In 2015, the U.S. Supreme Court determined that the EPA's failure to consider the compliance costs associated with limiting mercury emissions from the electric power sector was unreasonable. Michigan v. EPA, 135 S. Ct. 2699 (2015). At the time of publication, the D.C. Circuit had not decided whether to overturn the Utility MATS rule or keep the rule in place while the EPA revised its justification for promulgating the regulation. Because this Article relies on Utility MATS as a means of examining PUC decision-making, the outcome of the Utility MATS rule does not affect the analysis herein.

117. *See, e.g.*, Ky. Power Co., No. 2013-00430, 316 P.U.R. 4th 92 (Ky. P.S.C, Aug. 1, 2014), 2014 WL 3867888 (approving replacing one coal-fired unit with a natural gas turbine); Ky. Power Co., No. 2012-00578, 2013 WL 5592919, at *15 (Ky. Pub. Serv. Comm'n Oct. 7, 2013) (finding that retrofitting a 1078 MW coal-fired unit to comply with new environmental regulations "is not the lowest cost option"); Miss. Power Co., 2010UA279, 2012 WL 1484068 (Miss. Pub. Serv. Comm'n Apr. 3, 2012) (final certificate order).

118. *Miss. Power Co.*, 2012 WL 1484068, at *5.

119. *Id.* at *4.

120. *Id.* (noting that Units 1 and 2 began operating in 1977 and 1981, respectively).

operation of Plant Daniel's coal-fired units. The PSC responded by noting, "[B]ecause of the uncertainty concerning the exact requirements and timing of several impending regulations, the final combination of control technologies that will be needed in addition to the Scrubber Project cannot be finalized at this time."[121] Mississippi Power informed the commission that the scrubbers must be installed prior to any additional environmental controls that may ultimately be required at Plant Daniel.[122] The Company expected to file for a separate certificate for additional controls once more information became available concerning the other potential environmental controls that may be required for continued operation of the coal-fired units. Rather than hedging against the potential for future CO_2 emission limits, Mississippi Power argued that investing in Plant Daniel to comply with Utility MATS would "allow the Company to mitigate the risk to the existing fleet of future CO_2 compliance cost by allowing additional time for greater certainty about CO_2 regulations before committing to expensive environmental controls on the remainder of the fleet."[123]

The commission relied on the utility's economic modeling demonstrating that the retrofit option was the most cost-effective, finding that additional modeling by the Mississippi Public Utilities Staff to evaluate the decision under different future fuel price and policy scenarios was inconclusive.[124] The commission also considered fuel diversity, noting that opting to retire the units rather than retrofit them would result in natural gas making up seventy-one percent of the utility's energy mix.[125] In the end, the PSC placed "superior weight" on the retrofit option's benefits regarding fuel diversity and fuel security and determined that high CO_2 prices are not likely.[126]

A dissenting commissioner argued that retrofitting the units was the wrong decision, questioning the concerns about overreliance on natural gas and the hedging strategies of the firm.[127] The dissent asserted that Mississippi Power's analysis of its options was "based on

---

121. *Id.* at *6.

122. *Id.* ("The Company expects to file for a separate certificate for additional controls once more information is available concerning the other potential environmental controls that may be required for continued operation of Units 1 and 2 at Plant Daniel.").

123. *Id.* at *8.

124. *Id.* at *7-8.

125. *Id.* at *7 (finding "the strategic interest of fuel diversity very compelling and gives significant weight to this consideration").

126. *Id.* at *9.

127. Miss. Power Co., 2010UA279, 2012 WL 1484069 (Miss. Pub. Serv. Comm'n Apr. 4, 2012) (Presley, Comm'r, concurring in part and dissenting in part).

severe overestimations of future natural gas prices which naturally favored installation of scrubbers at Daniel."[128] According to the dissent:

> The primary strategic argument for the scrubbers is that the retention of coal in [Mississippi Power's] fuel mix achieves fuel diversity as protection from natural gas price volatility. As pointed out in the record, this again misstates a key issue. While diversity of generation is obviously important, its value is as a hedge against skyrocketing natural gas prices where the only alternative is natural gas fired generation. With the realization of gas prices as high as [Mississippi Power] predicts unlikely, and with a stable of alternatives as discussed above, the value of this hedging component diminishes. It diminishes so much, in fact, that the capital investment required to achieve diversity will eclipse any costs this diversity has avoided.
>
> Finally, [Mississippi Power] argues that the Daniel Units 1 and 2 must be retained as necessary baseload units. However, the term "baseload unit" is not synonymous with "coal-fired unit." When economics dictate, natural gas units can serve as baseload resources. In fact, Plant Daniel itself demonstrates this as its gas units have provided baseload power over the last two years where the coal units have not.[129]

The dissent also criticized the notion that investing in the $660 million scrubbers "pre-certif[ied] future ratepayer investment in the company and . . . continue[d] to put the Commission in a box" by admitting:

> [T]he scrubbers will be the first in a series of capital intensive environmental compliance requirements for Daniel Units 1 & 2 if they are to continue operation. . . .
>
> The conclusion that the public interest is only satisfied by approving the Daniel Scrubbers is based on false economic and strategic premises that misguided the debate. The decision in this case followed a trail of logic that was off target from the start. Therefore, the Commission arrived at the wrong destination. In convincing the majority that this path was correct, MPC has successfully set up another Kemper situation in which this or future Commissions will be forced to choose between allowing a "too big to fail" financial disaster for one of its utilities or placing the burden of its rescue on utility customers.[130]

128. *Id.* at *1 (relying on data from U.S. EIA and NYMEX).

129. *Id.* at *2.

130. *Id.* at *3.

The majority and dissenting opinions provide a stark contract when considering the bounds of prudency and least cost in a PSC proceeding. By noting the likelihood of more stringent environmental regulations in the future, the commission's majority considered least cost over time rather than taking a static view of least cost based on the laws and regulations in place at the time. However, the PSC did not engage in robust analysis of the future costs, instead relying on assertions by Mississippi Power. At the same time, the commission also noted the option's value of investing in the scrubbers in the near-term as a strategy to preserve options in the future.[131] In contrast, the dissent placed more faith in natural gas prices remaining relatively low and thus dismissed concerns about maintaining fuel diversity. By criticizing Mississippi Power's acceptance of additional costs arising from future environmental regulations, the dissent also implicitly argued for hedging regulatory risk by choosing an option that is more likely to avoid future costs.

4. *Appalachian Power Company Example: Rejection of a New IGCC Plant*

A 2007 proposal by Appalachian Power Company (APCo), an American Electric Power (AEP) subsidiary, to construct a coal-fired IGCC plant provides a further look at different interpretations of the least cost mandate. APCo, whose service territory spans portions of West Virginia and Virginia, proposed construction a 629 MW coal-fired IGCC facility in West Virginia.[132] The utility justified its proposal based on the potential to capture carbon emissions in the event the U.S. Congress adopted new legislation requiring emission decreases.[133] The project required separate approval from the commission in each state before moving forward with the $2.23 billion project, but it only received approval from the West Virginia PSC.[134] The Virginia State Corporation Commission (SCC) denied APCo's bid for approval, preventing the project from moving forward.[135]

---

131. Miss. Power Co., 2010UA279, 2012 WL 1484068, at *8 (Miss. Pub. Serv. Comm'n Apr. 3, 2012); *see infra* Section III.B for further discussion of options value.

132. Appalachian Power Co., No. PUE-2007-00068, 2008 S.C.C. Ann Rept. 405 (Va. State Corp. Comm'n Apr. 14, 2008), 2008 WL 1778119 (final order); Appalachian Power Co., No. 06-0033-E-CN, at 1 (W. Va. Pub. Serv. Comm'n Mar. 6, 2008) (comm'n order).

133. Appalachian Power Co., 2008 WL 1778119, at *3.

134. Appalachian Power Co., 263 P.U.R. 4th 297 (W. Va. Pub. Serv. Comm'n Mar. 6, 2008), 2008 WL 1758812.

135. Appalachian Power Co., 2008 WL 1778119, at *2 (denying APCo's application for a rate adjustment clause). The project would cost 40–105% more than a similar size pulverized coal facility. *Id.* at *3. APCo's filings indicated that the firm planned to seek federal funding to cover a portion of the construction costs. *Id.*; *see Appalachian Power Fact Sheet: Carbon Dioxide Capture and Storage Project*, CARBON CAPTURE & SEQUESTRATION TECHS.

Despite the project's cost, the West Virginia Commission was persuaded in part because it would

> enable APCo to continue to use native coal for the Project's expected life in a way that will provide superior thermal efficiency, will enable APCo to achieve significant reductions over the environmental impacts of the conventional coal combustion and will facilitate compliance with the constraints imposed by expected future environmental regulations.[136]

After accounting for the cost of future environmental regulations, the PSC found that the cost of electricity from the IGCC plant would be less than that from a new pulverized coal unit.[137]

The Virginia SCC came to the opposite conclusion from its counterpart in West Virginia, finding that the IGCC facility was "neither reasonable nor prudent."[138] The SCC questioned the viability of the technology and the accuracy of the cost projections.[139] The commission also dismissed the regulatory hedging value of the new plant because future CO_2 emission limits were too uncertain.[140]

Similar to the KY Power and Mississippi Power examples, the Virginia and West Virginia Commissions offer opposing views of regulatory risk and the degree of certainty necessary to justify rate increases. The APCo IGCC case also provides an example of the direct relationship between the views of commissioners and deployment of new energy technologies, as well as the challenge of deploying technologies that may present diffuse societal benefits but high localized costs.[141]

The group of PUC cases described in this subpart highlight the predominant role that near-term cost considerations play in a PUC proceeding, despite the fact that the dissenting opinions in the Kentucky Power, Duke Energy, and Mississippi Power examples and the different approaches of the two state commissions in the APCo example suggest that alternative views were possible under the respective state laws. Taken together, the cases demonstrate conflicting views of costs, risks, and benefits that may arise in a least cost inquiry and the subjectivity inherent in PUC decision-making. The

---

@ MIT, http://sequestration.mit.edu/tools/projects/appalachian_power.html (last visited Feb. 27, 2016).

136. *Appalachian Power Co.*, 2008 WL 1758812.

137. *Id.*

138. *Appalachian Power Co.*, 2008 WL 1778119, at *2.

139. *Id.* at *3-6.

140. *Id.* at *7-8.

141. Jonas J. Monast & Sarah K. Adair, *Completing the Energy Innovation Cycle: The View from the Public Utility Commission*, 65 HASTINGS L.J. 1345, 1381-83 (2014).

cases also demonstrate that choices regarding which variables to consider and how much weight to give each variable have a direct influence on the outcome. Each example reveals that reasonable commissioners may disagree regarding which risks to consider, how those risks relate to one another, and which alternatives are viable choices for the regulated utilities. These cases also highlight the difficulty of assessing and responding to policy uncertainty, leading many commissions to evaluate utility needs based on laws on the books at the time.

B. *Uncertainty, Irreversibility, and Inherent Value Choices*

The U.S. electricity sector is in the early phase of a major and costly transition that will ultimately result in the replacement of much of the nation's electricity infrastructure by the middle of the twenty-first century, including replacing the fleet of existing power plants, further incorporating renewable energy technologies, and transitioning the electricity grid to a digital system.[142] The resulting capital costs and projected minimal electricity demand growth during this time creates the potential for significant cost increases in electricity rates.[143] While the transition will occur over a period of decades, a series of near-term factors will directly affect private sector investments and the sector's long-term emissions trajectory, including fuel prices, technology advancements, and regulatory requirements. PUCs will play a central role in managing this transition.

Electricity markets were relatively predictable from the early-to-mid 1980s until recently. Coal prices were generally stable, while natural gas prices were characterized by wide price swings in the 1990s and early 2000s.[144] Electricity generation options were limited, with pulverized coal plants and nuclear plants offering viable options for dependable, affordable baseload power.[145] Natural gas turbines

---

142. *See, e.g.*, JONAS MONAST & DAVID HOPPOCK, NICHOLAS INST. FOR ENVTL. POLICY SOLS., DUKE UNIV., DESIGNING CO2 PERFORMANCE STANDARDS FOR A TRANSITIONING ELECTRICITY SECTOR: A MULTI-BENEFITS FRAMEWORK 11068 (2014); THE FUTURE OF THE ELECTRIC GRID: AN INTERDISCIPLINARY MIT STUDY (2011), http://mitei.mit.edu/system/files/Electric_Grid_Full_Report.pdf.

143. *Annual Energy Outlook 2015: Executive Summary*, U.S. ENERGY INFO. ADMIN. (Apr. 14, 2015), http://www.eia.gov/forecasts/aeo/executive_summary.cfm ("Rising costs for electric power generation, transmission, and distribution, coupled with relatively slow growth of electricity demand, produce an 18% increase in the average retail price of electricity over the period from 2013 to 2040 in the AEO2015 Reference case.").

144. *Table 7.9 Coal Prices, Selected Years, 1949-2011*, U.S. ENERGY INFO. ADMIN. (2011), http://www.eia.gov/totalenergy/data/annual/pdf/sec7_21.pdf; *U.S. Natural Gas Wellhead Price*, U.S. ENERGY INFO. ADMIN. (Dec. 31, 2014), http://www.eia.gov/dnav/ng/hist/n9190us3m.htm.

145. U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2014 WITH PROJECTIONS TO 2040, at IF-34 (2014), www.eia.gov/forecasts/archive/aeo14/pdf/0383(2014).pdf (finding that

and oil-fired boilers provided intermediate and peak power due to their ability to ramp up or down based on electricity demand and the higher fuel costs.[146] Solar and wind power were unable to compete on a cost basis and relied on subsidies and mandates.[147] Existing power plants were exempt from many of the new environmental regulations that emerged in the early 1970s.[148] Electricity demand was generally predictable, with the notable exception of the decline in demand in the late 1970s and early 1980s.[149] This drop in demand, due to an economic recession and the difficulties utilities encountered with financing and permitting of nuclear power plants in the aftermath of the Three Mile Island accident, led to cancelled projects that resulted in over $15 billion in stranded costs that were largely borne by ratepayers.[150]

A range of economic, technical, and regulatory factors are driving profound shifts in the U.S. electricity sector, creating a complex matrix of risks that electric generators and regulators must understand and address. For example, the shale gas boom has led to a rapid drop in natural gas prices, and current projections from the U.S. Energy Information Administration and NYMEX futures prices suggest that the average price per mmBtu could remain relatively stable for at least a decade or more.[151] In the near term, the low fuel cost makes

---

"[i]n 2012, coal-fired and nuclear power plants together provided 56% of the electricity generated in the United States" and noting that nuclear and coal operate as baseload power).

146. *See Natural Gas-Fired Combustion Turbines Are Generally Used to Meet Peak Electricity Load*, U.S. ENERGY INFO. ADMIN. (Oct. 1, 2013), http://www.eia.gov/todayinenergy/detail.cfm?id=13191.

147. *See, e.g.*, U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2008 WITH PROJECTIONS TO 2030, at 70 (2008), http://www.eia.gov/oiaf/aeo/pdf/0383%282008%29.pdf (noting that the modeling reference case projects "the growth potential of wind power, which depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of the Federal PTC [(Production Tax Credit)]" and that "[s]olar technologies in general remain too costly for grid-connected applications, but demonstration programs and State policies support some growth in central-station solar PV, and small-scale customer-sited PV applications grow rapidly").

148. *See* Jonathan Remy Nash & Richard L. Revesz, *Grandfathering and Environmental Regulation: The Law and Economics of New Source Review*, 101 NW. U. L. REV. 1677, 1681-96 (2007).

149. Pierce, *supra* note 26, at 502-03.

150. *See* Joseph P. Tomain & Constance Dowd Burton, *Nuclear Transition: From Three Mile Island to Chernobyl,* 28 WM. & MARY L. REV. 363, 377-78 (1987) (citing ENERGY INFO. ADMIN., U.S. DEP'T OF ENERGY, NUCLEAR PLANT CANCELLATIONS: CAUSES, COSTS, AND CONSEQUENCES ch. 2 (1983)).

151. *See Henry Hub Natural Gas Futures Settlements*, CME GROUP, http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html (last visited Feb. 27, 2016) (showing natural gas futures prices settling at, $2.654 for Sept. 2020 futures and $2.916 for Dec. 2027 futures); *see also Natural Gas Consumption Has Two Peaks Each Year*, U.S. ENERGY INFO. ADMIN. (July 1, 2011),

natural gas a likely option for new electricity generation.[152] However, because it is early in the shale gas boom, long-term price projections may be inaccurate. Historically, natural gas has displayed significant price volatility, and long-term price projections have been frequently proven unreliable.[153] Because the levelized operating cost for a natural gas plant is largely determined by fuel costs, as opposed to a coal plant or a nuclear plant where the cost is largely driven by construction costs, volatility in natural gas prices over the lifetime of a facility could result in significant rate spikes in areas with growing reliance on natural gas generation.[154]

Despite the prospect of long-term natural gas price volatility, new coal-fired generation in the United States is unlikely. Even before the rapid expansion of shale gas production and the resulting drop in natural gas prices, energy projections suggested that there would be little or no new coal-fired generation built in the foreseeable future,[155] with any increases in coal-fired generation resulting from increased dispatch from existing units. Coal's competitive advantage compared to natural gas was a result of the fuel price being relatively cheap and stable, a competitive advantage that is undermined by the dramatic increase of economically viable natural gas reserves in the United States due to horizontal drilling and hydraulic fracturing technologies.[156] The shift from higher average prices to lower average prices puts the cost of generating electricity from a natural gas-fired facility on par with that of a coal-fired facility.[157] The increasing costs

---

http://www.eia.gov/todayinenergy/detail.cfm?id=2050 (showing cyclical increases in NYMEX futures prices are due to increased winter demand).

152. U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2015 WITH PROJECTIONS TO 2040, at 8-9 (2015), http://www.eia.gov/forecasts/aeo/pdf/0383%282015%29.pdf.

153. The rapid emergence of economically viable shale gas resources may limit price volatility moving forward. *See, e.g.*, *Natural Gas Prices Drop Following Strong Production Growth*, U.S. ENERGY INFO. ADMIN. (Jan. 28, 2015), http://www.eia.gov/todayinenergy/detail.cfm?id=19751; *U.S. Crude Oil and Natural Gas Proved Reserves*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/naturalgas/crudeoilreserves/archive/2013/index.cfm (last updated Dec. 19, 2014) (finding that "[a] sharp increase in proved natural gas reserves in 2013 more than offset the significant decline experienced in 2012, and set a new record (354 trillion cubic feet) for U.S. natural gas proved reserves") (footnote omitted).

154. *See Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015*, U.S. ENERGY INFO. ADMIN. (June 3, 2015), http://www.eia.gov/forecasts/aeo/electricity_generation.cfm [hereinafter *Levelized Cost*].

155. *See* Steve James, *Feature-US Coal-Fired Power Plant Plans up in Smoke?* REUTERS (Mar. 4, 2007), http://www.reuters.com/article/2007/03/04/coal-power-idUSN0232700720070304.

156. *See* U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2013 WITH PROJECTIONS TO 2040, at 39-42, 79 (2013), http://www.eia.gov/forecasts/archive/aeo13/pdf/0383%282013%29.pdf.

157. *Electric Generator Dispatch Depends on System Demand and the Relative Cost of Operation*, U.S. ENERGY INFO. ADMIN. (Aug. 17, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7590.

of operating coal-fired power plants and the prospect of increasing stringency on emissions of CO_2 and other air pollutants not only make new coal-fired generation unlikely, these factors also raise questions about the viability of the nation's existing fleet of coal-fired power plants.

Uncertainty regarding the nation's existing fleet of nuclear power plants highlights the emergence of yet another vexing issue facing electric utilities and their regulators. The operating permits for the majority of the nation's nuclear power plants will expire in the 2030s,[158] forcing utilities and regulators to decide between seeking permit extensions and retiring facilities before plants reach the end of their operating license.[159] With the average ten to twelve year planning horizon to construct a new nuclear plant, operators and regulators will need to determine whether to replace facilities with new nuclear generation before the end of the decade. Factors such as natural gas prices, climate policy, uncertainty regarding electricity demand growth, and concerns about price volatility and fuel diversity will play important roles in the decision-making process.

The electricity sector will face increased infrastructure expenditures independent of generation decisions in order to respond to the need for new transmission lines and smart grid improvements.[160] If electricity demand remains stagnant, utilities will likely have to raise rates in order to recover the costs of new infrastructure, potentially further depressing demand. Flat demand can also raise questions regarding whether to undertake major capital projects because there may not be the need for the capacity once the facility is completed, potentially resulting in underutilized or stranded assets and consumers paying higher prices to compensate the utilities for poor

---

158. *See Almost All U.S. Nuclear Plants Require Life Extension Past 60 Years to Operate Beyond 2050*, ENERGY INFO. ADMIN. (Dec. 8, 2014), http://www.eia.gov/todayinenergy/detail.cfm?id=19091(explaining that the bulk of existing nuclear power plants were licensed before 1990 and that an operating license issued by the Nuclear Regulatory Commission (NRC) is good for a period of forty years).

159. Many of these nuclear units have already received one license extension from the NRC. *Id.* (noting that the NRC has granted twenty-year license renewals to 74 out of the 100 operating reactors in the United States).

160. For example, the Brattle Group has estimated that the sector will spend between $120–$160 billion per decade on new transmission through 2030. JOHANNES PFEIFENBERGER ET AL., THE BRATTLE GROUP, INVESTMENT TRENDS AND FUNDAMENTALS IN US TRANSMISSION AND ELECTRICITY INFRASTRUCTURE 11 (2015), http://www.brattle.com/system/news/pdfs/000/000/904/original/Investment_Trends_and_Fundamentals_in_US_Transmission_and_Electricity_Infrastructure.pdf?1437424727. A 2012 Deloitte report estimates that investments in new electricity generation will reach $150 billion in the same time period, while smart grid investments between 2012–2015 could amount to $4.4–$11.6 billion. GREGORY ALIFF, DELOITTE, THE MATH DOES NOT LIE: FACTORING THE FUTURE OF THE U.S. ELECTRIC POWER INDUSTRY 4 (2012), http://www2.deloitte.com/content/dam/Deloitte/global/Documents/Energy-and-Resources/dttl-er-themathdoesnotlie-08082013.pdf.

planning decisions. The history of unfinished nuclear power plants in the aftermath of the 1970s recession and the Three Mile Island nuclear disaster offer a cautionary tale for regulators considering large capital expenditures during a period of significant uncertainty.[161]

However, a decision-maker cannot freeze in the face of uncertainty. Investments must be made to maintain reliable electricity service. How to do so, what costs are incurred by various options, and who pays those costs all raise unavoidable value choices. The strategies by which electric utilities and their regulators address these uncertainties will determine the trajectory of electricity rates and the sector's environmental impacts for decades to come.

Uncertainty is not a new challenge for the electricity sector, as utility executives and regulators have long had to grapple with the prospect of changes in technology, fuel prices, and regulation. However, the scope and scale of uncertainties, and the fact that these factors are converging at the same time that utilities are retiring large numbers of older coal-fired power plants and determining whether and how to replace the retiring generation, present a particularly challenging decision-making environment for current PUCs.

Compounding the challenges associated with regulatory decision-making in the face of uncertainty is the fact that capital investments for generation decisions are irreversible.[162] The current U.S. electricity infrastructure primarily depends upon large power plants to generate electricity. Initial capital investments can range from approximately \$1000–\$1400 per kilowatt for new natural gas combined cycle units, and approximately \$2800–\$5700 per kilowatt for a new nuclear unit.[163] Once those investments are made, either the shareholders or ratepayers must pay.[164] Risk allocation is a key difference between a typical investment by a corporate actor facing market competition and an investment by a rate-regulated electric utility. Once a PUC

161. *See* Pierce, *supra* note 26, at 504-05.

162. *See, e.g.*, Miss. Power Co., 2010UA279, 2012 WL 1484068, at *8 (Miss. Pub. Serv. Comm'n Apr. 3, 2012) (final certificate order) (noting that installing a scrubber to comply with Utility MATS "was largely 'irreversible,' because a decision to control would dictate that future environmental controls be added and, further, because Daniel is the newest coal units, a decision not to control would likely lead to similar decisions with respect to the remaining coal units in [Mississippi Power's] fleet").

163. KAPLAN, *supra* note 73, at 79-83 (listing project costs for proposed and completed nuclear and natural gas combined cycle projects). The text uses price-per-kilowatt to provide a common unit for comparison due to variation in the size of projects. *See id.* The total project costs range from \$330 million to \$9.9 billion, with net summer capacity ranging from 300 to 2700 megawatts. *Id.*

164. *See, e.g.*, Jersey Cent. Power & Light Co. v. Fed. Energy Regulatory Comm'n, 730 F.2d 816 (1984) (considering how to allocate costs incurred for a nuclear unit that did not become operational).

incorporates a utility investment into the rate base, the commission must set rates at a level that allows the utility's investors to recoup their investments plus a rate of return.[165]

The combination of uncertainty and irreversibility are distinctive risks facing commissioners overseeing rate-regulated industries, such as vertically-regulated electric utilities.[166] At the same time, the latitude available to utility commissioners creates an opportunity to address a wide range of societal impacts resulting from electricity generation. Conversely, failure to take an expansive view of the factors that contribute to long-term costs associated with operating various types of power plants could result in the PUCs failing to achieve the least cost mandate that underlies so much of their decision-making processes. Furthermore, rigid adherence to the narrow view of constrained least cost could frustrate the tripartite aims of affordability, reliability, and allowing reasonable returns on investment.

IV. MAXIMIZING UTILITY THROUGH THE LEAST COST FRAMEWORK: FROM THEORY TO PRACTICE

The premise that PUC decision-making is, at its core, an attempt at maximizing societal utility calls for a critical assessment of the scope of the regulatory process. Whose utility is the regulatory process attempting to maximize, and relatedly, is the goal overall utility or utility among a narrow band of criteria? The impacts of an electric utility's decision may be felt across a utility's service territory, a state, a region, the nation, or the globe. For example, reliance on cheap electricity from coal throughout the twentieth century resulted in high levels of mercury emissions, which are known to cause severe neurological impacts; sulfur dioxide and nitrogen oxides emissions, which are known to contribute to respiratory problems and to be the leading cause of acid rain;[167] and greenhouse gas emissions,[168] which are known contributors to global climate change.[169] These impacts not

165. Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 692-93 (1923).

166. Cass R. Sunstein, *Irreversible and Catastrophic*, 91 CORNELL L. REV. 841, 842-43 (2006).

167. *See Health*, U.S. ENVTL. PROT. AGENCY, http://www3.epa.gov/airquality/sulfurdioxide/health.html (last visited Feb. 27, 2016); *What is Acid Rain?*, U.S. ENVTL. PROT. AGENCY, http://www3.epa.gov/acidrain/what/index.html (last visited Feb. 27, 2016).

168. *See generally U.S. Greenhouse Gas Inventory Report: 1990–2013*, U.S. ENVTL. PROT. AGENCY, http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html (last visited Feb. 27, 2016) (providing an overview of greenhouse gas emissions in the U.S. and sources of greenhouse gas emissions).

169. *Causes of Climate Change*, U.S. ENVTL. PROT. AGENCY, http://www3.epa.gov/climatechange/science/causes.html (last updated Nov. 4, 2015); INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CLIMATE CHANGE 2014 SYNTHESIS REPORT 44-47,

only affect public health and the environment, but also may lead to more stringent regulations to reduce the impacts and therefore higher compliance costs for facilities emitting these pollutants. The financial impacts may also ripple well beyond the rates charged to consumers, potentially affecting a region's ability to attract new businesses as well as the value of retirement funds that are invested heavily in investor-owned utilities (IOUs) based on the expectation that these IOUs provide reliable returns.

Reasonable and responsible risk hedging can mitigate the potential for significant rate increases resulting from future regulations and fuel price volatility, while also reducing near-term public health and environmental impacts. Conversely, failure to fully consider the risk of changing circumstances affecting generation costs can have serious negative economic and environmental impacts. Depending on the factors commissions consider and the weight assigned to each factor, they may conclude that new generation is necessary and that higher or lower cost alternatives are more appropriate to meet demand and satisfy other important variables. Alternatively, commissions may conclude that the preferable action is to delay a major investment by reducing demand through energy efficiency or demand response. Investing in smaller scale generation options in the near-term may also provide an attractive option in some situations, as the approach may allow commissions to wait for more data to become available regarding the trajectory of natural gas prices or allow new technologies such as utility-scale energy storage options time to develop.[170] An option that often is not available to the PUC is simply refusing to make a decision, requiring the commission to rely upon the best information available at the time.

The following Sections describe three options for expanding the scope of utility planning and utility commission oversight by pursuing a "minimum regret" strategy through a robust assessment of potential future scenarios affecting the electric utility sector; seeking options that result in multiple benefits for the electricity sector, its stakeholders, and society as a whole; and shifting a higher degree of risk to utility investors to further motivate risk hedging by the firms.

---

http://www.ipcc.ch/pdf/assessment-report/ar5/syr/AR5_SYR_FINAL_All_Topics.pdf (last visited Feb. 27, 2016).

170. *See* David Hoppock & Dalia Patino Echeverri, *Using Energy Efficiency to Hedge Natural Gas Price Uncertainty*, NICHOLAS INST. FOR ENVTL. POLICY SOLUTIONS (2013), https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_13-02.pdf.

A. Maximizing Utility by Minimizing Regret

The range of scenarios considered and the assumptions regarding future electricity demand, technology, fuel prices, and regulation will directly influence the outcome of a PUC proceeding. Given the rampant uncertainties currently facing the electricity sector, there is an increased likelihood that PUC decisions could result in higher costs over the lifetime of a facility due to retrofits to comply with new regulatory requirements, stranded costs due to early retirement of a facility, or both. Near-term decisions based on current technologies may also fail to take advantage of lower cost alternatives that emerge over time. Explicitly assessing how alternatives compare on multiple objectives could help utilities and regulators identify investment alternatives on both cost and non-cost objectives that are likely to result in the broadest range of societal benefits.[171] Increasing transparency regarding the value choices inherent in the planning process can elucidate those inherent choices and also demonstrate the breadth of options available under the least cost framework.

The integrated resource plan (IRP) process, implemented in approximately half of the states, is perhaps the most direct attempt at a utility maximization approach. IRPs generally require electric utilities to explain to the PUC how they expect the electricity sector to change over time and identify plans for addressing the changes, although the processes differ significantly regarding the level of analysis and transparency.[172] While many commentators point to the bene-

---

171. The elements of a robust electric utility planning process closely resemble the seven-step "felicific calculus" that Bentham proposed as a means to evaluate alterative courses of action: intensity (i.e., how strong is the pleasure or pain); duration (i.e., how long will the pleasure or pain last); certainty (i.e., how certain is the actor that the pleasure or pain will occur); propinquity (i.e., how soon will the pleasure or pain occur); fecundity (i.e., will the action lead to similar pleasures or pains in the future); purity (i.e., how pure is the pleasure or pain); and extent (i.e., what is the net impact of the action). BENTHAM, *supra* note 8, at 3. Although Bentham used different language than contemporary utility planners and regulators, there are direct analogies between the elements of the calculus and the multiple variables that will determine the long-term cost of electricity and impacts of the system. *See id.* Mill refined Bentham's approach by noting that maximizing utility is not simply a quantitative exercise, adding up pleasures on one side and pains on the other. As Mill explained, some pleasures are more desirable than others and, conversely, some pains less desirable than others. In addition, some pleasures and pains are impossible to compare with one another. For example, intellectual pleasures and physical pains occur on different planes. J. S. MILL, UTILITARIANISM 57 (Roger Crisp ed., 1998) ("It is better to be a human being dissatisfied than a pig satisfied; better to be Socrates dissatisfied than a fool satisfied."). Similarly, PUCs may view some factors as more important than others, such as prioritizing reliability over environmental protection. *See, e.g.*, N. AM. ELEC. RELIABILITY CORP., POTENTIAL RELIABILITY IMPACTS OF EPA'S PROPOSED CLEAN POWER PLAN (2014), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf.

172. The IRP concept has its roots in the Public Utilities Regulatory Policies Act (PURPA). 16 U.S.C. §§ 2601-2645 (2012). PURPA established federal standards that,

fits of the IRP process,[173] the approach has not enjoyed universal support. For example, when efforts to implement IRP requirements and efforts to restructure electricity markets were in their early phases, Black and Pierce contrasted the "deregulatory trend" that "relies where possible on markets, private incentives, and decentralized decisions to produce optimal pricing and consumption of electric power and least-cost pollution control" with "faith in central planning ('integrated resource planning' is the new phrase)" and observed that IRP "bears an uncomfortable resemblance to the systems previously used to govern the economies of eastern Europe and the former Soviet Union."[174]

Such dire predictions about IRPs ushering in Soviet-era regulation for the U.S. electricity sector have proven unfounded, and there remain open questions regarding the pros and cons of restructuring electricity markets. Instead, IRPs can be an important tool in the effort to assess risks and impacts of electricity generation choices, but there are limits to the IRP process as conducted in many states. PUCs may lack the resources to perform independent verification, and nongovernmental stakeholders may therefore have difficulty engaging in the planning process. The process also depends on assumptions about future demand, fuel prices, and technology prices that may or may not prove to be accurate in the long run. Electric utilities often conduct the analysis using proprietary modeling tools that are not made available for PUC staff or stakeholders to test different assumptions. Commissions may also have limited opportunity to question the utility. Finally, utilities may have a disincentive to highlight scenarios that conflict with the firm's goals.

Despite these potential shortcomings, there are examples of IRP processes that consider a wider range of potential scenarios regarding economics, technology, and regulation. The process developed by the Tennessee Valley Authority (TVA) is a particularly robust effort to identify optimal planning pathways for the next twenty years after

---

though not mandatory, "would evolve into 'integrated resource planning' by the industry, where both generating facilities and load management/conservation techniques would be weighed in developing least-cost electricity services." Rudy Perkins, *Electricity Deregulation, Environmental Externalities and the Limitations of Price*, 39 B.C. L. REV. 903, 1004 (1998).

173. *See, e.g.*, Inara Scott, *Teaching an Old Dog New Tricks: Adapting Public Utility Commissions to Meet Twenty-First Century Climate Challenges*, 38 HARV. ENVTL. L. REV. 371, 409-10 (2014) ("Integrated resource planning is a powerful tool that can be used to weigh options for the future of the utility system. Planners can assess the long-term cost and reliability impacts of different transmission paths, distributed generation, renewable resources, and technology like the smart grid.").

174. Bernard S. Black & Richard J. Pierce, Jr., *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COLUM. L. REV. 1339, 1341-42 (1993).

considering a range of potential scenarios.[175] TVA defines the purpose of its resource planning as "[t]he application of economic and engineering analyses to the resource adequacy problem . . . specifically making investment decisions to minimize fixed and variable costs, while maintaining appropriate resource adequacy."[176] This is a variant on the least cost approach followed by many state PUCs. Characterized as a "no-regrets" approach, the TVA IRP process considers cost, financial risk, environmental stewardship, macro economic effects, and flexibility by evaluating numerous planning strategies across seven potential future scenarios.[177] TVA employees solicit stakeholder feedback on the range of scenarios included in the IRP process, and TVA summarizes the results in a scorecard that is easily accessible to the lay audience.[178] Together, these variables allow TVA "to make the best decisions in a dynamic, ever-changing regulatory and economic environment."[179]

Despite the robust planning and the explicit consideration of environmental impacts, the TVA's "no-regrets" planning process did not lead to the conclusion that it should retire all coal-fired generation. As recently as December 2014, the TVA directors opted to retrofit two 134 MW coal-fired units located in Kentucky for a cost of $185 mil-

---

175. TVA is not subject to state PUC oversight.

176. TENN. VALLEY AUTH., EXPLORING LEAST-REGRETS RESOURCE PLANNING: A FORUM ON MODELING FOR LONG-RANGE POWER SUPPLY STUDIES 3 (2014); Dallas Burtraw et al., *Reliability in the U.S. Electricity Industry Under New Environmental Regulations*, 62 ENERGY POL'Y 1078 (2013).

177. TENN. VALLEY AUTH., INTEGRATED RESOURCE PLAN: TVA'S ENVIRONMENTAL & ENERGY FUTURE 13-14 (2011), http://pbadupws.nrc.gov/docs/ML1217/ML12171A189.pdf. TVA defines a "no-regrets" process as one

> in which all relevant and available information was analyzed in a careful and considered fashion, with significant attention paid to what would happen if the future unfolds in an unexpected way.
>
> In other words, strategic options were analyzed not only from the perspective of what was expected to occur in the future, but also from the perspective of what was possible to occur in the future. Using this framework, decisions made today and in the near future are not overly dependent on the future unfolding exactly as expected. Therefore, this IRP should provide benefit and value to stakeholders even if the future turns out to be different than predicted.

Id. at 13; *see also* GARY BRINKWORTH, TENN. VALLEY AUTH., TVA'S 2015 IRP: MORE THAN A LEAST COST ENERGY PLAN (2014), http://www.aaes.auburn.edu/water/resources/Presentations/2014%20AL%20WR%20Conference/documents/3-Brinkworth-IRPoverviewALwaterconf0903a.pdf (summarizing the IRP framework).

178. *See* TENN. VALLEY AUTH., *supra* note 177, at 102-03; *see also* BRINKWORTH, *supra* note 177, at 13 (noting that resource plans are scored using a particular set of metrics reflected in the scorecard design).

179. TENN. VALLEY AUTH., *supra* note 177, at 10.

lion.[180] It does, however, more fully evaluate the costs and societal impacts of resource decisions, allowing decision-makers to better understand the potential outcomes of their actions.

Commissions wishing to take the broadest view of scenario analysis to develop a comprehensive evaluation of electric utility investments and their impacts could consider the following factors: the potential worst-case scenarios; the expected lifetime of a facility; the degree of uncertainty that could affect an investment's costs and impacts; how soon a decision must be made; and the potential for the investment to restrict choices in the future.[181] Undertaking such a broad analysis in a transparent fashion can elucidate the choices inherent in the process, demonstrate the breadth of options available under the least cost framework, and allow affected stakeholders to develop informed views regarding the future of a state's electricity sector.

Evaluation of worst-case scenarios may consider a range of factors relevant to the least cost inquiry, including costs associated with constructing and operating a facility, the potential impacts on system reliability, and the potential impacts on public health and the environment. The analysis may also consider the costs that could arise if unanticipated changes occur during the lifetime of the facility. The billions of dollars associated with abandoned nuclear construction projects in the 1980s are a prime example of the intensity consideration.[182] The drop in electricity demand that contributed to the decisions to abandon the nuclear projects also resulted in unfinished natural gas-fired facilities, but at a fraction of the cost.[183]

The degree of exposure to changing circumstances depends in large part on the expected lifetime of a facility. The longer a facility remains in operation, the more likely it is that new technologies will emerge that can generate electricity at a lower cost, reduce environmental impacts, or both. Regulatory requirements affecting energy production and delivery will change over time, and more stringent environmental regulations will likely be promulgated over time as

180. Dave Flessner, *$185 Million OK'd by TVA to Upgrade Kentucky Coal Plant*, TIMES FREE PRESS (Dec. 31, 2014), http://www.timesfreepress.com/news/business/aroundregion/story/2014/dec/31/185-million-okd-tva-upgrade-kentucky-coal-plant/280406/.

181. Although Bentham used different language than contemporary utility planners and regulators, there are parallels between the elements of the seven-step "felicific calculus" that Bentham proposed as a means to evaluate alterative courses of action and the multi-variable analytic process to produce a robust assessment of long-term cost impacts of electricity sector investments and potential externalities created by those investments. For an overview of Bentham's seven-step "felicific calculus" and John Stuart Mill's critique of the analysis, see *supra* note 171.

182. *See* Pierce, *supra* note 26, at 497-99.

183. *Id.* at 500-04.

new public health information emerges.[184] Additionally, new information will almost certainly emerge regarding electricity demand, public health impacts, and fuel prices. Duration does not counsel solely for projects with short lifespans. There may be value in knowing that an asset, once placed in service, would operate for long periods of time with relatively stable prices. For example, although nuclear power plants are quite expensive to build, they are relatively inexpensive to operate assuming no significant repair costs are necessary.[185]

As described above in Section III.B, significant uncertainty exists regarding the future of natural gas prices, future electricity demand, future technology costs, and future regulatory requirements. Unanticipated changes in one or more of these factors could result in dramatic rate increases, stranded assets (if operating a power plant becomes uneconomic before its capital costs are fully paid off), or both. The degrees of uncertainty may exist along a spectrum. For example, the policymaker applying this criterion may distinguish between near-term uncertainty in the potential for price volatility in natural gas markets, where limited supply results in temporary price spikes, and the potential for wide variation in long-term price trajectories. Regulatory uncertainty may also exist along a spectrum. Using mercury regulation as an example, electric utilities have known that limitations on mercury emissions were likely at some point during the lifetime of coal-fired power plants. Section 112 of the 1970 Clean Air Act required the EPA to regulate mercury emissions.[186] Frustrated with inaction, Congress overhauled the hazardous air pollution requirements in the 1990 Clean Air Act Amendments, resulting in a more prescriptive and stringent mandate.[187] Rather than require immediate regulation of mercury emissions from electric utilities, the revised section 112 included a compromise that required the EPA to undertake a study of the hazards to public health resulting from emissions at coal-fired electric generating units and regulate those emissions if the EPA Administrator determines that such regulation is "appropriate and necessary."[188] The EPA made such a finding in

184. *See* Jonas J. Monast & Sarah K. Adair, *A Triple Bottom Line for Electric Utility Regulation: Aligning State-Level Energy, Environmental, and Consumer Protection Goals*, 38 COLUM. J. ENVTL. L. 1, 7-8 (2013).

185. *See Levelized Cost*, *supra* note 154; *see, e.g.*, *Crystal River Nuclear Plant*, DUKE ENERGY, https://www.duke-energy.com/power-plants/nuclear/crystal-river.asp (last visited Feb. 27, 2016) (reporting Duke Energy's decision to retire the Crystal River nuclear plant in Florida due to significant repair costs).

186. Clean Air Act Amendments of 1970, Pub. L. No. 91-604, § 112, 84 Stat. 1676, 1685.

187. Clean Air Act Amendments of 1990, Pub. L. 101-549, tit. I, 104 Stat. 2399 (codified at 42 U.S.C. § 7412 (2012)).

188. 42 U.S.C. § 7412 (n)(1)(A).

2000.[189] This action put in motion a regulatory process that resulted in an overturned EPA proposal in 2008.[190] A follow-up rule was finalized in 2011.[191] Section 112 of the Clean Air Act requires compliance within three years after the EPA promulgates a final rule, with the possibility of a one-year extension for individual electric generating units.[192] Although the precise regulatory requirement was unknown until the promulgation of the final Utility MATS rule, there was increasing certainty that coal-fired power plants would face limits on mercury emissions.

In the electricity sector context, assessing the timeline for the decision is critical. Is electricity demand expected to grow significantly in the near-term? Does the near-term need preclude certain generation options with long permitting and construction timelines?[193] Are there strategies for delaying the decision, such as investments in energy efficiency, demand response, increased utilization of existing plants, or through power purchase agreements? As the Duke Energy Cliffside example demonstrates,[194] investments to meet a projected near-term need for additional capacity may constrain the options available to a PUC if future circumstances suggest an alternative approach could better serve electricity demand and mitigate costs. Assessing both the potential for the investment to contribute to low rates and reliable power as well as the potential for economic or regulatory developments to cause higher rates or reliability concerns may support a higher-cost investment if it is likely to produce desirable outcomes in a range of future scenarios.[195]

---

189. Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units, 65 Fed. Reg. 79,825 (Dec. 20, 2000).

190. New Jersey v. EPA, 517 F.3d 574, 578 (D.C. Cir. 2008) (vacating the Clean Air Mercury Rule).

191. Utility MATS, *supra* note 116.

192. 42 U.S.C. § 7412(i)(3)(B). Implementation timelines are uncertain in the aftermath of the U.S. Supreme Court's 2015 holding that the EPA must consider costs when determining whether regulation under section 112 is "appropriate and necessary." *See* Michigan v. EPA, 135 S. Ct. 2699, 2716 (2015).

193. *See, e.g.*, *Natural Gas Technology,* AM. ELECTRIC POWER, http://www.aep.com/about/IssuesAndPositions/Generation/Technologies/NaturalGas.aspx (last visited Feb. 27, 2016) ("Natural gas generating plants are constructed much more quickly than coal fired generation. Simple cycle plants are typically constructed in 18 to 30 months and combined cycle plants are constructed in about 36 months. These lead times are significantly less than the average for solid fuel plants (i.e. coal plants), about 72 months.").

194. *See* discussion *supra* Section III.A.2.

195. *See generally* Bean & Hoppock, *supra* note 64 (discussing how the decision-making timeline is affected by uncertainty).

B. Maximizing Utility by Seeking Multi-Benefit Strategies

Despite the limitations of economic assessments regarding long-term electricity system costs, it is nonetheless possible to identify categories of risks, such as increasing stringency of environmental policy or the potential for reduced demand, to result in stranded assets. As demonstrated in Part III, the least cost mandate is more malleable than is often appreciated by PUCs and could allow commissions to evaluate the range of possible actions against the risks facing the sector to identify strategies that minimize the risk. In addition to evaluating a broad range of options in an effort to minimize potential regrets if circumstances change, PUCs could include an additional layer of analysis to consider strategies that offer additional benefits in addition to affordable rates.

For example, the EPA's current efforts to limit CO_2 emissions from existing sources under section 111(d) of the Clean Air Act could be viewed as yet another challenge affecting near-term electric utility planning. The broad statutory language in section 111, combined with the limited application of section 111(d) and the lack of any judicial decisions interpreting the section, has led numerous scholars and stakeholders to conclude that compliance options could include a wide range of strategies to reduce emissions from the power sector as a whole rather than focusing on reductions at each individual covered unit.[196] This reading of section 111(d) compliance options, if upheld by the courts, could allow PUC commissioners and environmental regulators to seek regulatory approaches that achieve additional benefits for the electricity sector. For example, end-use energy efficiency may qualify as a compliance option under section 111(d).[197] It may also reduce near-term demand and allow utilities to delay capital investments during a period of uncertainty. Similarly, renewable energy generation could play a role in section 111(d) compliance while also increasing diversity in the energy mix as a means to hedge against natural gas price volatility.

Other multi-benefit strategies may include requirements that utilities act early to limit a range of pollutants in anticipation of more

---

196. *See, e.g.*, JEREMY M. TARR ET AL., NICHOLAS INST. FOR ENVTL. POLICY SOLS., DUKE UNIV., REGULATING CARBON DIOXIDE UNDER SECTION 111(D) OF THE CLEAN AIR ACT: OPTIONS, LIMITS, AND IMPACTS (2013), https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf; Ann E. Carlson & Megan M. Herzog, *Text in Context: The Fate of Emergent Climate Regulation After* UARG *and* Eme Homer, 39 HARV. ENVTL. L. REV. 23, 30 (2015); Jody Freeman & David B. Spence, *Old Statutes, New Problems*, 163 U. PA. L. REV. 1, 37 (2014); MONAST & HOPPOCK, *supra* note 142.

197. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, 64,664, 64,666 (Oct. 23, 2015) (codified at 40 CFR pt. 60 (2015)).

stringent regulations in the future. North Carolina's Clean Smokestacks Act, adopted in 2002, required utilities to limit SO_2 and NO_X emissions before the CAIR/CSAPR rules were promulgated.[198] The Clean Smokestacks Act instructed utilities to act early and provided a longer timeline to achieve compliance thereby allowing North Carolina's utilities to adjust retrofit decisions as they learned more about federal rules. As a result, North Carolina's utilities were largely unaffected by the CAIR, CSAPR, and the Utility MATS rules. These early steps not only avoided rate shocks when the rules were finalized, but also resulted in significant health benefits for North Carolina's citizens.[199]

While it is generally not within the purview of the PUC to directly address potential public health impacts, understanding the public health and environmental impacts of utility's choices can help PUCs better assess the risk of increased regulatory stringency. This information could allow PUCs to consider the potential long-term compliance costs associated with various options for meeting, or reducing, electricity demand. Explicit consideration of environmental impacts, therefore, may fit within the PUC's existing statutory mandate. PUCs may not have the institutional competency to fully assess these risks. More effective information sharing across state agencies, including coordination between environmental regulators and economic regulators, could address this hurdle.

C. Maximizing Utility by Dispersing Risk

Once a PUC determines that a utility investment was prudently incurred, the risk of the investment generally shifts to consumers.[200] If electricity demand drops or other generation options become more cost effective—both situations that have occurred in the aftermath of the 2008 economic recession—utilities may still recover the full cost of the original investment. Although PUCs may not reverse decisions incorporating prudent utility investments into the rate base, utilities and their investors still face a degree of financial risk with large-scale infrastructure investments. The cost of capital may rise, or projects may face cancellation due to cost overruns or technological failures.[201] The most notable examples of utility sector investor risk are found in post hoc efforts to allocate the costs of nuclear units that

198. *See* sources cited *supra* note 65.

199. *See* Andrews, *supra* note 57; Hoppock et al., *supra* note 57.

200. *See* discussion *supra* Section II.A.

201. Monast & Adair, *supra* note 141, at 1375-76 (citing Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-014, Miss. Power Co., at 30, 32, 82 (Apr. 24, 2012)).

never entered service, thus failing the "used and useful" test.[202] PUCs may also preemptively limit the total costs that ratepayers will face due to cost overruns, providing a firm signal for utilities to incorporate such costs into the investment risk analysis.[203]

As previously discussed in Section III.B, technology is changing rapidly, the price of renewable energy is continuing to fall, natural gas prices may experience periods of volatility, and the economy may continue to become more energy efficient.[204] Given the level of uncertainty facing electricity providers and regulators, both of whom are responsible for ensuring that there is a sufficient supply of electricity to meet demand at all times, it may require a rethinking of what qualifies as a prudent investment. For example, energy efficiency and demand response investments may allow utilities to delay new capital investments until they have more information about demand growth and the stability of natural gas supply. Power purchase agreements in lieu of capital investments may also allow utilities to gather more information before acting. There could also be a preference for smaller scale generation or generation with a shorter construction lead-time.

This approach could shift some level of risk back to utilities and their shareholders, which is a delicate balance and could affect utilities' ability to attract capital. Shareholders may view this approach as reducing overall utility because it creates a disincentive for investment by increasing risk and potentially significantly reducing returns. Ratepayers may also face higher prices if utilities are seen as a more risky investment and thus charged higher interest rates to access capital. This should not be seen as an absolute barrier to partial risk shifting. Investors already accept investment risk in other contexts. While investors may prefer the certainty that comes along with guaranteed returns on investment, consumers would prefer not to be solely responsible for long-term investments that may result in higher electricity rates. Reallocating some business risk could result in better decisions in the long-term, but it is an important factor to understand and balance with other goals.

Shifting risk could cut both ways regarding energy innovation.[205] This strategy could make it more difficult to pursue early-stage tech-

---

202. *See, e.g.*, Jonathan A. Lesser, *The Used and Useful Test: Implications for a Restructured Electric Industry*, 23 ENERGY L.J. 349, 356-57 (2002); James J. Hoecker, *"Used and Useful": Autopsy of a Ratemaking Policy*, 8 ENERGY L.J. 303, 314 (1987).

203. *See* Monast & Adair, *supra* note 141, at 1377.

204. *See supra* Section III.B.

205. Monast & Adair, *supra* note 141, at 1375-76.

nologies such as coal-fired generation with carbon capture technologies due to the high capital costs, long planning and construction horizon, and considerable uncertainty regarding future electricity demand and technology costs for other generation options. On the other hand, shifting a degree of risk away from ratepayers does not necessarily place the risk on shareholders. Public policy choices to support innovative energy technologies through tax credits, federal loan guarantees, and technology grants may allow early stage technologies to enter the marketplace without requiring ratepayers to bear the cost and technology risk.

V. CONCLUSION

PUC decisions will play a critical role in determining how the electricity sector evolves over the next few decades, including the rates consumers will pay and the societal impacts that will result. The least cost framework provides commissioners a significant amount of discretion to consider the full suite of potential actions and their impacts, even if their state legislatures do not explicitly instruct them to value non-cost objectives. Failure to consider the wide range of potential impacts could result in higher costs over the operating life of a facility, and failure to evaluate potential costs and benefits resulting from an electric utility decision could frustrate the underlying goal of PUC processes: providing the greatest good to the greatest number by ensuring a long-term, affordable, and reliable electricity sector.