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The Regulatory Contract in the Marketplace

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Abstract

For decades, energy policy has struggled to reconcile two distinct visions for the future: the first seeks ever-more-competitive, efficient, and dynamic electricity markets; while the second seeks an ever-greener mix of electricity generation sources. Caught within this push-and-pull dynamic is the regulatory contract—a nineteenth-century concept that stands more for ordered regulation than competitive markets. This Article examines how piecemeal pursuit of two energy visions has produced mismatches between rapidly evolving markets and governance institutions that cannot change as quickly. To better evaluate these mismatches, the Article develops a framework that accounts not just for market operation and environmental externalities, but also the technical constraints of grid operation and electricity fuels. Relying on the experience of nuclear power, the Article creates an account of how a fuel source can be priced out of the market despite its apparent advantages in reliability and air emissions. With this understanding, the Article evaluates the political economy and governance challenges associated with diverse policy options aimed at better capturing valuable attributes of electricity. Ultimately, this analysis furthers our understanding of the regulatory contract in the marketplace, suggesting an updated vision for its role in mediating the competing goals for electricity markets.

The regulatory contract is undergoing a profound reformation. Once a cornerstone of progress dating at least to the Industrial Revolution, the model—under which an entity “clothed with the public interest” assumes basic duties and submits to price regulation in exchange for a monopoly franchise—has been used to build everything from bridges to power lines.¹ Markets, however, have become the norm for many formerly regulated industries, leaving vestiges of regulatory regimes that fit awkwardly with competition.² This is nowhere more apparent than in

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¹ Munn v. Illinois, 94 U.S. 113, 126 (1877) (upholding price regulation of grain elevators affected with the public interest); see also The Proprietors of the Charles River Bridge v. The Proprietors of the Warren Bridge, 36 U.S. 420, 557 (1837) (McLean, J., conc.) (referencing contractual relationship between government and bridge proprietors); Jersey Central Power & Light v. FERC, 810 F.2d 1168, 1189 (D.C. Cir. 1987) (Starr, J., conc.) (providing description).
² The debate between those who favor markets and those who favor regulations undergirds many of the issues we address here. One can find tensions between the two throughout the scholarly literature, spanning decades. See, e.g., Stephen Breyer, Analyzing Regulatory Failure: Mismatches, Less Restrictive Alternatives, and Reform, 92
energy policy, particularly as it struggles to reconcile two distinct visions for the future of electricity: the first seeks ever-more-efficient and dynamic markets; the second seeks ever-greener, low-impact electricity.

Pursuit of both visions has effected significant change in how electricity is valued—and at the intersection of this push-and-pull dynamic is the regulatory contract. The days of state-regulated utilities providing electricity monopoly service to customers are waning, replaced by dynamic wholesale markets populated by merchant generators. In wholesale electricity markets, the Federal Energy Regulatory Commission (FERC) operates not so much as a rate-setting agency, but as the overseer of a regionally operated market. In states that have embraced retail competition, state public utility commissions (PUCs) fill a similar role; traditionally regulated states continue to set rates, but struggle to efficiently interface between their retail interests and those of the wholesale market. States are no longer simply parties to this contract, nor are they the only parties to it. Rather, states are now only one of several regulatory entities influencing markets.

Along with the move toward competitive markets, efforts to encourage cleaner electricity have also had a significant impact on the electricity sector. Indeed, some of these efforts have been intertwined with the move toward markets. The energy crises of the 1970s, for example, produced the Public Utilities Regulatory Policies Act of 1978 (PURPA), a statute aimed at both incentivizing cleaner electricity and ensuring its access to the grid. State renewable portfolio standards (RPSs) and Integrated Resource Planning (IRP) also emerged from this era, further pushing alternative electricity resources that could compete in the market against traditional sector, particularly for fossil-fueled electricity. The Clean Air Act (CAA), for example, now regulates more pollutants, from more plants, more stringently, than ever before.

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3 See infra Part I (developing evolution of electricity markets).


5 See infra Part III.B.2. (describing relevant litigation).


7 See infra Part I.B (discussing these developments).


Environmental Protection Agency’s (EPA’s) recent proposals to limit greenhouse gas (GHG) emissions from fossil-fueled generators are just the latest steps in that process.  

What are the impacts of these changes? Some argue competitive pressures will bring about a utility “death spiral,”11 environmental regulation will produce a “train wreck”12 of inadequate generating capacity, and both forces will set grid reliability back decades.13 Others welcome disruptive technologies and business models,14 arguing that a green, market-based system is impossible without a complete overhaul of traditional utility law. The stakes are high: electricity disruptions cost billions of dollars;15 poorly designed markets are vulnerable to manipulation;16 more than half a million people die each year from the health impacts of coal-fired emissions;17 and the need to mitigate and adapt to climate change is only growing more urgent.18 The governance challenges and implications alone are staggering, and, at this point, anything but clear.19

12 See MCCARTHY & COPELAND, supra note 9, at 1-3 (summarizing train wreck argument).
19 See, e.g., Oneok, Inc. v. Learjet, Inc. (In re W. States Wholesale Natural Gas Antitrust Litig.), 715 F.3d 716 (9th Cir. 2013), cert. granted, 134 S. Ct. 2899 (2014) (considering preemptive sweep of Natural Gas Act’s provisions
Policymakers, courts, and scholars have made important contributions to understanding each of these issues.\textsuperscript{20} What is missing from the discussion, however, is an integrative framework—an analytical approach that permits disciplined consideration of how all of the concerns raised above work together. In this Article, we develop such a framework—one that accounts not just for market operation and environmental externalities, but also the technical constraints of grid operation and electricity fuels. Implicit in our approach is the view that the market-based and environmental imperatives need not trump one another, notwithstanding the tensions between them. Moreover, any vision of the energy future ought to also seek to maximize reliability. Obtaining low-cost, low-impact, reliable electricity is a tall order, but we believe that a self-conscious analysis of exactly what the trade-offs are is a prerequisite to reaching that goal.

After developing our tripartite framework, we make it concrete using the example of nuclear power. Nuclear power, once heralded as the clean energy of the future,\textsuperscript{31} has been priced out of the market despite its apparent advantages—the absence of carbon or other emissions, its inexpensive fuel, its reliability, and its admirable safety record in the United States. Using our framework, we show how the struggle between the environment imperative and the market imperative, as mediated by politics and perceptions, has led to this counter-intuitive outcome.

This analysis tests our framework, demonstrates its broader workability, and helps identify various policy options that can better reconcile the parameters of cost, environmental impact, and reliability. Bringing our analysis full circle, we then construct a typology of policy options. Some of the options we present are prompted by our analysis in this Article; others are drawn from current experimentation and proposals developed in the existing literature. By paying careful attention to how these options fit within our tripartite framework, we can identify the mechanisms by which they would either alter the markets, or alter the value of what is traded on the markets. This exercise provides insights into the practicability of each option, but it also demonstrate regulatory federalism turned on its head, with increasing heterogeneity at the subnational level. Indeed, this suggests future research needs—most critically, the need to

\begin{thebibliography}{99}

that are read in pari materia with similar Federal Power Act provision); Elec. Power Supply Ass’n v. FERC, 753 F.3d 216 (D.C. Cir. 2014), pet’n for cert. filed Jan. 15, 2015 (holding Order 745 invalid as beyond FERC’s jurisdiction and concluding pricing rationale was arbitrary and capricious); PPL Energyplus, LLC v. Solomon, 766 F.3d 241 (3d Cir. 2014), pet’n for cert. filed Dec. 10, 2014 (holding New Jersey effort to compensate new generation for capacity market disparities was preempted by Federal Power Act); PPL Energyplus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014), pet’n for cert. filed Nov. 26, 2014 (similar).
\end{thebibliography}
consider how various proposals would compliment or hinder one another if implemented simultaneously. 22

Ultimately, this analysis furthers our understanding of the regulatory contract in the marketplace. 23 The move to a green, competitive electricity market has not eliminated the regulatory contract: the law continues to charge regulators with many of the same duties under competition as it did under price regulation. And holders of private capital continue to rely on those legal institutions in deciding whether to invest in the provision of electric services. But what was once mandated and compensated by regulatory fiat under the old system is now bought or sold in a competitive market. We show how these changes create new roles for all parties to the contract.

Part I of this Article begins with an overview of the shift from traditional rate regulation to competitive markets for electricity. 24 To ensure an appreciation for the technical aspects of electricity, this part provides an overview of how the electric grid is operated. 25 Next, Part I lays out our analytical framework, providing details on how three criteria—cost, reliability/flexibility, and externalities—are valued (or not) in electricity markets. 26 The final section of Part I considers the theory and practice of markets, drawing heavily from the economics literature to further contextualize our framework. Part II offers a full analysis of the “nuclear risk premium,” 27 identifying where it comes from, why it exists, and how it is that this low-emission, reliable technology is disadvantaged in competitive markets. We demonstrate that a combination of regulatory pressures, risk perception mechanisms, and market flaws has prevented competitive markets from valuing nuclear power’s desirable attributes as fully as they were valued under the traditional regulatory contract. Part III begins by delving into the political economy of modern electricity markets, emphasizing the governance challenges posed by the changing regulatory contract. Next, we examines a series of policy options that address the market’s failure to optimize cost, reliability, and environmental value. 28 In so doing, we consider various objections and legal hurdles to the options, but we do not ultimately offer a hard-and-fast prescription. Rather, we hope that our framework furthers the search for a principled analysis for the energy policy decisions that matter most today and that arise in the future. We conclude with some observations about the implications of our analysis for regulation, and regulated industries, in general.

I. Electricity Markets and the Grid

The last three decades have seen dramatic change in the relationship between energy regulators and prospective investors in electric generating plants. That change has played out in

22 The need is particularly strong as states grapple with the implications and uncertainties of EPA’s proposed Clean Power Plan. See infra Part III.B.2. (describing state’s reluctance to adopt policy options in light of uncertainty regarding Clean Power Plan).
23 This analysis may also be relevant to other traditionally regulated industries that interface with markets, such as communications. See Barbara van Schewick, Network Neutrality and Quality of Service: What a Nondiscrimination Rule Should Look Like, 67 STAN. L. REV. 1 (2015) (providing framework for considering future net neutrality rules).
24 See infra Part I.A.
25 See infra Part I.B.
26 See infra Part I.C.
27 See infra Part II.
28 See infra Part III.A.
an iterative back-and-forth between market participants and policymakers, and it has yielded a new regulatory environment that entails considerably more risk for prospective investors than their twentieth-century counterparts ever faced. In order to understand why that is, it is necessary to understand how electricity markets work, how the electric grid works, and the roles of different types of generation sources in the electric system—both historically and today.

A. The Evolution of Modern Markets

Built on the back of a regulatory contract, the American electric grid developed to serve the relatively localized needs of investor-owned utilities (IOUs). But it soon grew into an enormous, interconnected set of systems of mostly alternating-current transmission and distribution lines. Although IOUs dominated the industry, other kinds of electric service providers—primarily municipal utilities and rural cooperatives—grew up in areas left unserved by IOUs. These interconnected systems comprise three grids in the continental United States: the Eastern Interconnection, the Western Interconnection, and the Texas Interconnection. Within each of these three systems, virtually every generator of electricity is connected (however indirectly) with virtually every consumer of electricity.

Because electricity cannot be stored in commercial quantities economically, the grid must be kept in balance: that is, at any given point in time, the amount of electricity being dispatched to the grid by generators must equal the amount being taken off the grid by consumers. If loads are not balanced, the system will fail, causing blackouts for example. To keep loads in balance, the operators of the grid must marshal information about historic usage patterns, weather forecasts, generators’ operational plans, and the like to estimate levels of supply and demand in the near-term and longer-term future. With that information, operators can have generation


30 Generally we use the term “transmission” to refer to the movement of electric current over longer distances at higher voltages (so-called bulk power transfers), and “distribution” to refer to the delivery of electricity at lower voltages from high-voltage transmission lines to end-users. “Voltage” is a measure of the electric potential between two points and is the basis for rating transmission or distribution lines. Generally, transmission lines move power at voltages exceeding 110 kilovolts (kV); some transmission lines, however, move power at voltages in excess of 1000 kV. Distribution lines move power at less than 110 kV, typically between 4 and 34.5 kV. For a primer on these topics, see generally JACK CASAZZA & FRANK DELEA, UNDERSTANDING ELECTRIC POWER SYSTEMS (2010).

31 See infra note [10] (describing other electricity providers).


33 It is this interconnectedness, along with the tendency of electric current to flow along the path of least resistance (often across state lines), that subjects most electricity transmission to federal regulation under the FPA. See 16 U.S.C. § 824(b) (claiming federal jurisdiction over “transmission of electric energy in interstate commerce”); FPC v. Fla. Power & Light Co., 404 U.S. 453 (1972) (affirming Federal Power Commission (FPC) jurisdiction on this basis).

34 The North American power grid is maintained a frequency of 60 Her (Hz). If the grid strays too far from this frequency, the system fails. CASAZZA & DELEA, supra note 30, at 47-48.

35 See Matt Davison et al., Development of a Hybrid Model for Electrical Power Spot Prices, 17 IEEE TRANSACTIONS ON POWER SYS. 257, 260 (2002) (“It is known that power demand is tightly linked to weather and follows predictable seasonal and diurnal patterns.”).
resources ready to dispatch power, or demand-side resources ready to curtail their usage, when needed.\textsuperscript{36}

For most of the history of the American electric system, these balancing services were performed almost exclusively by IOUs, which provided monopoly service to their customers. IOUs generated most of the power they sold and supplied it over lines they owned.\textsuperscript{37} Rate regulation protected consumers against monopoly pricing, and ensured that utilities would earn a reasonable rate of return on most of their investments in generation.\textsuperscript{38} On those rare occasions when utilities found it necessary to buy wholesale power from a neighboring utility during times of shortage, they coordinated these transactions informally, knowing that the cost of the transaction would be recovered through rates.\textsuperscript{39} FERC exercised ratemaking jurisdiction over wholesale power sales, and state PUCs regulated retail rates.\textsuperscript{40} Utilities controlled access to the grid, and had little need to access wholesale power markets. For these reasons, merchant generators—those selling primarily into wholesale markets—were virtually unheard of prior to the late 1970s.

This state of affairs predominated in the electricity industry well into the 1990s. The generation mix came to be dominated by utility-owned plants using conventional fuels—first coal, hydroelectric, and oil facilities, and later natural gas and nuclear facilities. The seeds of change, however, were sown more than a decade earlier with the passage of PURPA.\textsuperscript{41} PURPA introduced non-utility generators into the market\textsuperscript{42} and incentivized renewable generation, which led to the construction of hundreds of merchant wind, solar, biomass, small hydro and gas-fired cogeneration facilities across the United States. These nonutility generators, in turn, created pressure for nondiscriminatory access to the electric grid so that they could sell their electricity directly to retailers or industrial customers. In 1996, FERC promulgated Orders 888 and 889, which mandated (a) unbundling electricity transmission from electricity sales, and (b) that owners of transmission lines act as common carriers providing transmission service on a nondiscriminatory basis to affiliated and non-affiliated companies alike.\textsuperscript{43} Along with this


\textsuperscript{37} A sizeable minority of customers receive their electric service from government entities—municipal utilities or other governmental agencies, like the Tennessee Valley Authority—or rural electric cooperatives. See Boselman et al., Energy, Economics and the Environment ch. 2 § B.2.b (4\textsuperscript{th} ed. forthcoming 2015) (surveying various types of service providers).

\textsuperscript{38} Id., at ch. 8, section B.2 (describing the basic principles of rate regulation). [Note typical approach is either prudent investment or used and useful—cross-reference to discussion for nuclear.] For a discussion of these concepts, see Jersey Central Power & Light Co. v. FERC, 810 F.2d 1168 (D.C. Cir. 1987); and Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989).

\textsuperscript{39} This informal coordination was managed through “power pools,” voluntary associations of IOUs and municipal utilities established to facilitate coordination along utility boundary lines. Casazza & Delea, supra note 30, at 56.

\textsuperscript{40} See 16 U.S.C. § 824(a) (limiting federal jurisdiction over power sales to wholesale sales in interstate commerce).

\textsuperscript{41} 16 U.S.C. §§ 2601-45.

\textsuperscript{42} PURPA promoted both electricity conservation programs and alternative forms of electricity production by providing financial incentives to new, nonutility producers of renewable electricity and cogeneration, designated as qualifying facilities (QFs). 18 C.F.R. pt. 292.

\textsuperscript{43} Order 888, supra note 4; Open-Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (May 10, 1996) (codified at 18 C.F.R. pt. 37) [hereinafter Order 889]; see also 16 USCS § 824j (providing for open access to transmission lines under some circumstances); New York v. FERC, 531 U.S. 1 (2002) (upholding Order 888). Under Order 888, transmission providers are required to file open access transmission tariffs (OATTs), which must meet various criteria. See 18 C.F.R. § 35.28 (describing requirements).
unbundling, FERC authorized most wholesale sellers of electricity to charge market-based rates.\textsuperscript{44}

At around the same time, some American states began to introduce competition and market-based rates into their retail markets, with California, Texas, and New York leading the way.\textsuperscript{45} As part of this restructuring, incumbent utilities in these competitive retail markets sold most of their generation assets or spun them off into subsidiaries, increasing the profile of independent merchant generators, marketers and brokers within the industry. This led to sharp increases in the number and volume of arms-length transactions on wholesale electricity markets, straining the capacity of both the transmission grid and regulators.\textsuperscript{46} In response, FERC pushed owners of transmission lines to form “independent system operators” (ISOs) and “regional transmission organizations” (RTOs) to help manage the provision of transmission services and oversee wholesale power markets.\textsuperscript{47}

Today, these ISOs/RTOs manage the day-to-day operation of wholesale power markets, schedule ancillary services (reserves necessary to balance load), and ensure that there is sufficient generating capacity over the long term to meet projected demand.\textsuperscript{48} They can ensure adequate reserves in either or both of two ways. One way is by relying on the price signal, as is done in the ERCOT system in Texas.\textsuperscript{49} A second approach is to create and manage separate capacity markets, in which owners of electricity generating facilities are paid to have capacity available in the event that it is needed in the future.\textsuperscript{50} In the PJM, New England and New York systems, for example, the relevant ISOs run capacity markets like these.

Today, there are seven major ISOs or RTOs in the United States, managing a significant portion of the power grid.\textsuperscript{51} In parts of the grid not so managed—mainly the southeast and the

\textsuperscript{44} See, e.g., California ex rel. Lockyer v. FERC (9th Cir. 2004) (upholding FERC’s use of market-based rates).
\textsuperscript{46} The U.S. Energy Information Administration (EIA) tracks wholesale power transactions at individual trading hubs. At the NEPOOL hub (located in the New England), there were about 1500 trades completed in 2001, involving approximately 1.37 million megawatt-hours (MWh) of electricity; in 2013, there were more than 6700 trades involving 5.76 million MWh. EIA, WHOLESALE ELECTRICITY AND NATURAL GAS MARKET DATA (2015) available at: http://www.eia.gov/electricity/wholesale/#history.
\textsuperscript{47} See Order 888, supra note 4, at 21,595–96 (establishing requirements for ISOs); Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg 809 (Jan. 6, 2000) (similar for RTOs). For purposes of this analysis, there is no meaningful distinction between ISOs and RTOs.
\textsuperscript{48} The term “reserves” refers to generating capacity that is currently unused but which is available to serve load; if that capacity is already running, so that operator may dispatch its electricity to the grid on very short notice, it qualifies as “spinning reserves.” “Regulation” services are the grid management activities that maintain frequency and voltages at their proper level, to ensure grid reliability. Willett Klempton & Jasna Tomic: Vehicle-to-Grid Power Fundamentals: Calculating Capacity and Net Revenue, 144 J. POWER SCI. 268, 275 (2005).
\textsuperscript{49} The Brattle Group, ESTIMATING THE ECONOMICALLY OPTIMAL RESERVE MARGIN IN ERCOT 1 (2014); see also infra Part III.B.3. (describing ERCOT’s approach to capacity); William W. Hogan, On an “Energy Only” Electricity Market Design for Resource Adequacy, JFK SCH. OF GOVT., HARV. UNIV., at 134 (2005) (noting energy-only markets change, but do not eliminate, regulatory interventions).
\textsuperscript{51} The seven are: the New England ISO (ISONE), covering the New England states; the New York ISO; the PJM Interconnection (PJM), stretching from the Chicago area to the mid-Atlantic states; the Midcontinent ISO (MISO), stretching from Minnesota south to south-central part of the country (excluding Texas); the Southwest Power Pool (SPP), covering portions of the plains states; the Electric Reliability Council of Texas (ERCOT); and the California ISO.
mountain west—the old system of IOU-centric markets, power pools, and traditional rate regulation prevails.

B. The Operation of Competitive Wholesale Markets

In competitive wholesale power markets, prices are determined by the forces of supply and demand rather than regulatory fiat. Prices are set in two settings: (a) longer-term bilateral power purchase agreements (PPAs); and (b) real-time or day-ahead spot markets. In the PPA setting, a generator or other wholesale seller bargains with a retailer or other buyer to reach a contractual agreement. Spot markets, by contrast, are multilateral, and the price is established through an auction—a bidding process that establishes a market clearing price for individual time increments during the day. Market prices must satisfy the Federal Power Act’s (FPA’s) requirement that rates be just and reasonable, and FERC has long determined that both PPA prices and spot market prices satisfy this standard.

Despite the widespread use of PPAs, grid operators do not take PPAs into account in their dispatch decisions. Rather, when the grid operator dispatches power from individual electric generating facilities to the grid, it does so on a least-cost basis. That is, from any status quo level of demand, as the next increment of power is needed to satisfy additional demand, the grid operator dispatches power from the available generating facility that is willing to provide the power at the lowest cost. Generally, grid operators deviate from this priority rule only to ensure the security of the power system—to avoid severe congestion or other operational problems that could be associated with dispatching the least-cost unit. Thus, the grid operates on a “security-constrained, least-cost dispatch” or “security constrained economic dispatch” (SCED) rule. This rule protects ratepayers from paying unnecessarily high (unjust and unreasonable) rates, and applies both in traditionally regulated systems and in competitive wholesale markets.

Ideally, competitive wholesale spot markets work in sync with the SCED principle. For each time increment during the day, sellers and buyers submit their bids indicating how much they are willing to pay and accept, respectively, for power. The operator matches buyers’ and sellers’ bids and determines the market clearing price, which all sellers will receive and buyers will pay, for power dispatched to the system during that time increment. Sellers should bid into the market at a price that reflects their short-run marginal cost of supplying power, that is, the cost of providing one additional unit of power. A large number of factors can influence the

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52 Most electricity retailers secure power using both PPAs and the spot market; in some wholesale markets all power deliveries are priced through the spot market, and PPAs serve only as a price hedging mechanism. See Bob Mango & John A.C. Woodley, The Inevitable Commoditization of Electric Power Markets, 132 FORTNIGHTLY 27, 31 (1994) (describing use of contracts as hedges for spot markets).

53 For a discussion of the operation of modern spot markets, see BOSSelman ET AL., supra note 37, ch.10.

54 FPA § 205, 16 U.S.C. § 824d.


57 Id.

marginal cost of dispatching a particular plant at a particular time. For example, a thermal plant operating at less than full capacity will have a lower marginal cost of providing the next unit of power than it would if it had to provide the additional power from a cold start. Sometimes, the plant with the lowest marginal cost is located in the wrong place, such that dispatching power from that plant will cause congestion that threatens security of the system. Taking these and other factors into consideration, the operator may perform this market clearing function for multiple locations (nodes) within the system, and may adjust prices to reflect congestion—so-called “nodal” pricing, or locational marginal pricing (LMP).

In theory, dispatch decisions could incorporate not only the generator’s costs, but social or external costs (such as estimated costs of pollution emitted by the generator) as well. In practice, no grid operator does so. Instead, the SCED principle means that public policies favoring renewable power influence dispatch decisions only indirectly, by impacting the price at which sellers will be willing to sell (and buyers to buy) power into the system at various time increments the following day. For example, the production tax credit for renewable generators depresses the willingness-to-accept bids of qualified renewable generators by paying them approximately two cents per kilowatt-hour (kwh) of power dispatched to the grid. State renewable portfolio standards can have a similar effect on willingness-to-accept bids, because sellers earn revenue from the sale of renewable energy credits for each kwh dispatched to the grid.

From this description it should be evident that competitive wholesale electricity markets entail much more price risk (for parties on both sides of the market) than traditionally regulated electricity markets. The PPA is one way to hedge that price risk. Least-cost dispatch rules may prevent the seller from delivering power to the buyer, but the sale obligation (at the contract price) remains, requiring a financial settlement between buyer and seller. Wholesale electricity market participants can use energy derivatives to hedge risk as well.

In sum, energy markets have undergone fairly profound changes over the last few decades, and the regulatory contract has changed along with them. Fifty years ago informal associations of IOUs kept the grid operating cooperatively, knowing that rate regulation insulated them from price risk. Now, in much of the country, those informal arrangements have been replaced by arms-length market transactions that subject the market participants to price risks. What is the role of the regulatory contract in this setting? Even where cost-of-service ratemaking remains the norm, the line between FERC’s and PUCs’ jurisdiction has shifted. The Supremacy Clause dictates that states must permit state retailers to pass wholesale costs through to customers, and generators that sell into the wholesale markets must take the market price. Thus, we increasingly rely on spot markets to provide the best signals to investors about

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60 Indeed, economists and engineers have proposed algorithms for these kinds of “environmental/economic dispatch,” or “social cost dispatch,” systems. See infra Part III.B.3. (discussing this approach).

61 For most of the last three decades Congress has enacted tax credits for renewable power sources. The production tax credit has hovered around 2 cents per KWh. See, e.g., 26 U.S.C. § 45 (1.5 cents/KWh).


64 The line is anything but clear. See, e.g., sources cited supra note 19 (providing overview of litigation).

65 Miss. Power & Light Co. v. Mississippi, 487 U.S. 354, 356 (1988); see Nantahala Power & Light Co. v. v. Thornburg, 476 U.S. 953, 965 (1986) (“interstate power rates filed with FERC or fixed by FERC must be given binding effect by state utility commissions determining intrastate rates”). The latter point, as it relates to capacity
the optimal mix of fuel sources, storage, and demand-side resources, raising the question whether markets can meet that challenge.\textsuperscript{66}

\textbf{C. Electric Generation: Serving Markets and the Grid}

In competitive wholesale electricity markets, generators and other wholesale sellers seek to maximize revenue from the sale of power. By contrast, grid operators seek to keep the grid and wholesale power markets running smoothly and efficiently. In this section we evaluate different electricity generation sources from the grid operator’s point of view, using three sets of criteria: (1) cost; (2) reliability/flexibility; and (3) negative externalities. Obtaining reliable electric service that is as inexpensive as possible implies a mix of different kinds of electricity generation—some that can operate efficiently at high outputs in order to supply base load, and others that can react efficiently to sudden changes in demand by ramping up and down quickly and at a reasonable cost. Moreover, fuel diversity also protects the public against the cost effects of sudden or sharp increases in the price of a particular fuel. Toward this end, state utility laws typically articulate the goal of a diverse generation mix.\textsuperscript{67} Although the environmental and social costs of electricity generation are not a direct component of grid dispatch and are not directly valued on the wholesale market, they are of concern to EPA and the states, and the object of their regulatory attention, which puts pressure on the electricity market structure. This, in turn, raises a number of important questions about the boundaries of regulators’ jurisdiction (both horizontal and vertical), a point to which we also return in Part III.

There are tradeoffs to be made between minimizing out-of-pocket cost to ratepayers, having a generation mix that is flexible enough to ensure reliability, and minimizing negative externalities. Each of the major electricity generation source types—coal, natural gas, nuclear, hydro, wind and solar—\textsuperscript{68}—bring different strengths and weaknesses to the task of serving these various goals. Some are more costly than others. Some can ramp up and down more efficiently

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\textsuperscript{67} See e.g., \textit{Del. Code. Ann. tit. 26, § 1007} (2015) (directing Delaware state regulators to ensure that utilities consider fuel diversity in acquiring new capacity); \textit{Fla. Stat.} § 403.519 (2015) (directing Florida Public Utilities Commission to consider need for fuel diversity and supply reliability when determining need for new power plant); \textit{id.} § 366.05 (authorizing Florida commission to require installation of particular generation sources upon finding of insufficient fuel diversity in state’s generation mix); \textit{N.Y. Pub. Serv. Law} § 164 (McKinney 2015) (making fuel diversity one of the evaluative criteria in New York’s electric generation siting approval process).

\textsuperscript{68} We focus on these five sources because the first four comprise the majority of electric generation today (ninety-two percent in 2013), and because the last two, along with natural gas, comprise the majority of projected future growth in generation (more than ninety-five percent). See \textit{EIA, FAQ: What Is U.S. Electricity Generation By Source}, http://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3 (last visited Mar. 4, 2015); \textit{EIA, Natural Gas Solar and Wind Lead Power Plant Capacity Additions in First Half of 2014} (Sept. 9, 2014), http://www.eia.gov/todayinenergy/detail.cfm?id=17891. Our consideration of solar power focuses on central station solar serving the grid, not distributed rooftop solar. Note that this list does not include energy storage or demand side resources; these resources supply energy or load reductions to the grid, respectively, but in much smaller amounts. Nevertheless, the framework we develop in this Article can be applied to these other resources as well. See Joel B. Eisen, \textit{Who Regulates the Smart Grid? FERC’s Authority Over Demand Response Compensation in Wholesale Electricity Markets}, 4 San Diego J. Climate & Energy L. 69 (2013) (analyzing jurisdictional issues associated with demand response).
and quickly than others. And of course, some have much more significant environmental costs than others.

1. Cost

Naturally, IOUs and investors jealously guard their cost data, but many entities publish estimates of the relative costs associated with different electricity fuels. We begin with the levelized cost of energy (LCOE). The LCOE represents the real-dollar cost per kilowatt-hour (kwh) of building and operating an electricity generation plant over the financial and operating life of the plant. Thus, it includes capital costs, fuel costs, fixed and variable operating and maintenance (O&M) costs, and financing costs. Investors care about LCOE because it represents an estimate of the average amount of money the plant owner must earn over the plant’s life in order to break even on the investment. These estimates are based on a large number of assumptions, and here, for illustrative purposes only, we present data from two sources—the Energy Information Administration (EIA) and the consultant Lazard.

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69 Thus, we are unable to present figures for bid prices in the wholesale markets.


Figure 1. Levelized Cost Estimates for Generation Sources

<table>
<thead>
<tr>
<th>Generation Source</th>
<th>EIA LCOE Estimate 2012 $/MWh</th>
<th>Lazard Estimate 2014 $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>95.6</td>
<td>66-151</td>
</tr>
<tr>
<td>Natural Gas – CT&lt;sup&gt;b&lt;/sup&gt;</td>
<td>128.4</td>
<td>179-230</td>
</tr>
<tr>
<td>Natural Gas – CCNG&lt;sup&gt;c&lt;/sup&gt;</td>
<td>66.3</td>
<td>61-87</td>
</tr>
<tr>
<td>Nuclear</td>
<td>96.1&lt;sup&gt;d&lt;/sup&gt;</td>
<td>124-132</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>84.5</td>
<td>No estimate reported</td>
</tr>
<tr>
<td>Wind – onshore</td>
<td>80.3</td>
<td>37-81</td>
</tr>
<tr>
<td>Solar – PV&lt;sup&gt;e&lt;/sup&gt;</td>
<td>130</td>
<td>60-86</td>
</tr>
<tr>
<td>Solar – CSP&lt;sup&gt;f&lt;/sup&gt;</td>
<td>243</td>
<td>118-130</td>
</tr>
</tbody>
</table>

<sup>a</sup>Unless otherwise noted, reported estimates assume technologies currently in use, without carbon capture.
<sup>b</sup>CT means combustion turbine.
<sup>c</sup>CCNG means combined cycle natural gas plant.
<sup>d</sup>EIA assumes advanced nuclear, reflecting current new construction and a dual-reactor plant. Lazard also incorporates current new construction but presumes a single-reactor plant.
<sup>e</sup>PV means photovoltaic solar. The reported estimates are for central station PV rather than rooftop PV.
<sup>f</sup>CSP means concentrated solar, a thermal technology that heats water into steam to drive a turbine.

Several observations regarding the data deserve emphasis. First, they are for new construction, and generally reflect the existing regulatory landscape. We provide more detail on the contours of that landscape in Part II infra, but note for now that different sources face different regulatory regimes, as well as very different assumptions about the future regulatory

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<sup>72</sup> The Advanced Nuclear technology assumes the Westinghouse AP1000 reactor design, which is being installed at the Vogtle site, as described infra Part II.C. See EIA, UPDATED CAPITAL COST ESTIMATES FOR UTILITY SCALE ELECTRICITY GENERATING PLANTS, at 12-1 (2014), available at http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf (describing assumptions).

<sup>73</sup> EIA’s figures assume plants will begin operating in 2019. EIA LCOE Estimates, supra note 70, at 6.

<sup>74</sup> Subsidies for some fuel sources are calculated by EIA, but not presented here. EIA LCOE Estimates, supra note 70, at 3. EIA also assumed an added 3% to the cost of capital for greenhouse-gas intensive technologies, reflecting investor concerns rather than the regulatory landscape. See id. at 2-5; see also EIA, ASSUMPTIONS TO THE ANNUAL ENERGY OUTLOOK 6 (2014), available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/introduction.pdf. [hereinafter EIA Assumptions]. Lazard assumes carbon capture technology at the high end of its coal and CCNG estimates. Lazard LCOE Estimates, supra note 71, at 2.
landscape. Given those assumptions, the traditional base load sources—coal and nuclear—are significantly more expensive than CCNG, new onshore wind farms, or (according to Lazard), new central station photovoltaic solar plants. This observation is consistent with the relative lack of planned new construction for coal and nuclear, and the growth of natural gas-fired and renewable generation.

Second, a closer look at the components of LCOE provides a sense of the relative capital costs of newly constructed plants. On a per-megawatt-hour (MWh) basis, the capital costs of nuclear, wind, solar PV, and coal are quite high compared to CCNG. EIA estimates the levelized capital cost at $71.4/MWh for a new nuclear facility (74% of LCOE), $114/MWh (88% of LCOE for solar PV), $64/MWh (77% of LCOE) for wind, and $60/MWh for a coal facility (63% of LCOE). By comparison, the corresponding capital cost estimate for CCNG is only $14.3/MWh (21% of LCOE). Note that for nuclear, high capital costs reflect longer construction periods (and hence, higher financing costs), more specialized components, and the need for highly skilled labor, among other things.

Finally, note that the LCOE data reported in Figure 1 include assumptions about the “capacity factors,” that is, the percentage of time the plants will be dispatching into the grid over their projected lifetimes. Because investors must pay the capital costs of new plants up front, they must try to predict capacity factors over the forty-plus year life of the plant. If these facilities have higher capacity factors than assumed in the analysis, their capital costs per MWh will be lower; if the facilities have lower capacity factors, capital costs per MWh will be higher. Even in traditionally regulated markets controlled by vertically-integrated IOUs, capacity factors may be difficult to predict, given reliance on SCED and the possibility of drastic changes in relative fuel prices, costs imposed by new regulations, and the rise of disruptive new technologies. However, in traditionally regulated markets, investors who overestimate their facility’s capacity factors often expect that they will nevertheless recover their capital costs and a fair rate of return. Not so in competitive wholesale markets, where the SCED rule will ultimately determine plant revenues. Further, the capacity factors for intermittent renewables like wind, solar, and some hydro are not directly comparable to the others because their generating time is not driven by grid operators, but rather on natural conditions.

Another factor important to investors, and included in LCOE, is the cost of fuel. Fuel costs are a key component of fossil-fueled plant’s variable operations and maintenance (O&M)

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75 For a different calculation of LCOE that considers the impact of a carbon cost, see MIT Study (2009 update), supra note 71, at 6. This study predicts that a cost of $25 per ton of carbon would make the LCOE of nuclear fall below that of coal and natural gas. Id.
76 EIA, ANNUAL ENERGY OUTLOOK, 2014: MARKET TRENDS, available at http://www.eia.gov/forecasts/aeo/MT_electric.cfm (“natural gas-fired plants account for 73% of capacity additions from 2013 to 2040 in the Reference case, compared with 24% for renewables, 3% for nuclear, and 1% for coal”).
77 EIA LCOE Estimates, supra note 70, at 6.
78 Id.
80 Many nuclear power plants have obtained amendments to their licenses permitting uprates, meaning they can now run at higher capacities than initially permitted; others have canceled their uprate requests in light of lower capacity needs. EIA 2014 Assumptions, Electricity Market Module, supra note 74, at 101.
81 There are numerous provisos, some of which are considered infra Part II.C.
82 Id. at 3. Even comparing generators’ capital costs on the basis of nameplate capacity (that is, dollars per unit of energy the generators can produce), the upfront investment in a nuclear plant is 6 or 7 times that of CCNG facility, and 4 times that of a solar PV or wind farm. Lazard’s LCOE Estimates, supra note __, at __. See also Black & Veatch, supra note 000, at 9-48 (providing similar relative ordering).
costs, and are thus an important component of those plants’ short-run marginal costs (which will form the basis of market bid prices).\textsuperscript{83} Natural gas prices are projected to remain relatively low, due in large part to the shale gas revolution. Wind and solar generation have no fuel costs, so their variable O&M costs approach zero. Nuclear also has competitively low fuel costs (lower than coal).\textsuperscript{84} Thus, EIA estimates the variable O&M costs of natural gas the highest ($49-82/MWh), followed by coal ($30/MWh), nuclear ($12/MWh), hydro ($6/MWh) and wind and solar ($0/MWh).\textsuperscript{85} Taking all of the above data into consideration (not only variable O&M), it stands to reason that in competitive energy markets the cost criterion will point investors toward new gas-fired, wind and solar power, and away from coal-fired and nuclear power.

Remember that these cost data reflect estimates for new generating facilities, averaged over the useful life of the facilities. But the U.S. generation fleet includes existing generating plants that have been operating for decades, and may have recovered all or a significant portion of their capital costs through regulated rates. To the extent that these plants can operate after their capital costs have been paid, they can offer power to the grid at prices that are below their levelized costs. For example, consider again nuclear power’s low fuel costs compared to coal; the nuclear fuel costs also differ from coal in that they do not vary with plant output over the short run.\textsuperscript{86} Thus, the short-run marginal costs for nuclear power ought to be nearly zero.\textsuperscript{87} Why then, are many older nuclear power plants built in the 1970s and 80s not able to submit competitive bids into American spot markets?

The full answer to that question is developed in Part II, but note that regardless of fuel source, the logic of bidding (and of the SCED rule) in competitive spot markets does not ensure that plant owners will earn a positive return on investment. First, sometimes plants with competitive bids are not dispatched due to technical grid issues. Second, even if a plant is dispatched, the plant will not earn a positive return on investment unless the average market-clearing price over time exceeds the plant’s long-run average costs.\textsuperscript{88} Further, public policies and market forces have depressed short-run marginal costs in the industry. The shale gas revolution has depressed natural gas prices, and hence, marginal cost-based bids from natural gas-fired generators. As described in the next section, natural gas is a peaking fuel, so its costs tend to drive the clearing price. Increasing penetration of zero-marginal-cost renewables, along with renewables subsidies, also depresses bids from those sources such that spot prices in some markets are sometimes negative.\textsuperscript{89} An additional competitor, providers of demand-response (DR) services, ought to further depress market prices over the long run as well.\textsuperscript{90} Overall, these forces increase the percentage of time when market clearing prices fall below some plants’ long-run average costs.

\textsuperscript{83} The marginal operating cost will also include fixed O&M, like service on debt, and, in the case of nuclear, payments for insurance, decommissioning, and waste management. See infra Part II.D. (discussing these costs).
\textsuperscript{84} EIA LCOE Estimates, supra note 70, at 6.
\textsuperscript{85} Id.
\textsuperscript{88} Long-run average costs reflect the total of a plant’s marginal costs averaged over its lifetime. Id.
\textsuperscript{89} See id. (providing details).
\textsuperscript{90} See generally Eisen, supra note 68 (explaining role of DR in energy markets and debate over how DR should be compensated in those markets).
2. Reliability/Flexibility

A diversity of generation fuels makes the overall system flexible, promoting grid reliability. Some generation sources can respond quickly to changing system needs, while others excel at providing the constant power needed to serve base load. A diverse mix ensures efficient use of these attributes. Generally, existing coal-fired and nuclear plants were designed to run at full capacity for extended periods to serve base load, and they do not cycle (turn on and off) or ramp up and down as efficiently as gas-fired or hydroelectric plants. By forcing a coal-fired power plant to cycle more frequently (or ramp more quickly) than its design specifications suggest, for example, the operator imposes excess wear and tear on the plant, and emits more pollution per MWh of power produced than it would by remaining within design specifications. Natural gas combustion turbines, by contrast, were designed for load following: they can cycle and ramp much more efficiently and quickly than coal-fired or nuclear plants.

Because of their intermittency, neither wind nor solar facilities can provide the load-following services offered by fossil-fueled plants. To the contrary, their intermittency increases the load-following burden on grid operators by adding another source of short-term variation in addition to variations in demand. Wind and solar facilities vary the amount of power they supply to the grid, but because their marginal costs are so low, their power tends to be dispatched to grid whenever they are operating. When the wind stops blowing or changes speed, or the sun stops shining, grid operators must call on other resources to balance loads.

Because reliability is dependent on a mix of generation characteristics, it is also sensitive to the availability and cost of fuel. Like coal, for example, uranium is relatively inexpensive and worldwide reserves are considered substantial. Moreover, both coal-fired and nuclear power plants have storage capacity: coal can be stockpiled onsite, and nuclear fuel assemblies last about eighteen months to two years. This capacity hedges the risk of supply interruptions, further enhancing these sources’ reliability for electricity generation. The history of natural gas-fired power is different. Historically, natural gas prices were relatively high and volatile,

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91 See MIT ENERGY INITIATIVE, MANAGING LARGE-SCALE PENETRATION OF RENEWABLES 11 (Apr. 20, 2011), available at http://mitei.mit.edu/system/files/intermittent-renewables-full.pdf (describing cycling and ramping). The only hydroelectric plants that can follow load are those operated in storage mode; many such plants, however, operate in run-of-the-river mode, meaning that the amount of water passing through the turbines is equal to the amount of water flowing from the reservoir to downstream; this is done to keep the reservoir at a constant level. See BOSSELMAN ET AL., supra note 37, ch. 6 (setting forth legal regime for hydropower).


93 See generally B&V Study, supra note 71 (listing ramp rates and “quick start” rates for various generation technologies); MIT ENERGY INITIATIVE, supra note 91, at 11, 27 (providing various ramping rates and noting that ramping a nuclear plant quickly requires more operator involvement, increasing the risk of operator error).

94 See MIT ENERGY INITIATIVE, supra note 91, at 17-21 (describing system impacts of intermittent generation).

95 For this reason, many have argued that natural gas pairs well with intermittent renewables because of its load-following capabilities. E.g., Puga, supra note 92. Demand-side resources also have a role to play in this regard. Eisen, supra note 68, at 79-80.

96 Davis, supra note Error! Bookmark not defined., at 59. Also like coal, uranium is available domestically. However, currently only about 17% of uranium delivered in the United States is of U.S. origin. EIA, 2013 URANIUM MARKETING ANNUAL REPORT 1 (2014), available at http://www.eia.gov/uranium/marketing/pdf/2013umar.pdf. More than half the enrichment, however, takes place in the United States. Id. at 2. The Nuclear Energy Institute reports that efforts are underway to revitalize the U.S. uranium production industry. NEI NUCLEAR FUEL SUPPLY: ABUNDANT SUPPLIES OF URANIUM, http://www.nei.org/Issues-Policy/Nuclear-Fuel-Supply (last visited Feb. 19, 2015).
reflecting both periodic insecurity about domestic supply and the relative lack of storage capacity on the interstate pipeline system.\textsuperscript{97} The shale gas revolution, however, now holds the prospect of price stability and ample domestic supply for the future.\textsuperscript{98} But natural gas-fired power plants are still dependent on the interstate and local pipeline systems through which they acquire their fuel; fuel is typically not stored on site.\textsuperscript{99}

Of course, for wind, solar and hydro plants, respectively, their “fuels”—wind, sun and water—are produced locally, and are essentially free of charge. Rather, the primary threat to reliability for these technologies is weather-induced intermittency—the possibility that the sun won’t shine, the wind won’t blow, or river flows will be too low. For that reason, EIA classifies these three technologies as “non-dispatchable,” meaning that they cannot be counted on to deliver power when needed the way fossil-fueled and nuclear plants can.\textsuperscript{100} Moreover, we can make a distinction between the predictability of power from these sources and its variability. Wind power, in particular, can be variable in ways that affect generation output. Forecasters may be able to predict that the blades of the wind turbine will be turning one hour from now; however, it may be difficult to predict exactly how fast they will be turning (and therefore, how much power the turbine will be generating). Proponents of wind and solar power argue that a suite of geographically distributed wind and solar power plants could be counted on to serve a specified level of load reliably because the sun won’t stop shining, or the wind stop blowing, everywhere at the same time.\textsuperscript{101}

3. Negative Externalities and Risk

All electric generation technologies produce negative externalities—harm to health, safety and the environment over their full life cycle.\textsuperscript{102} The extraction of coal, natural gas, uranium and silicon (or other minerals used in manufacturing PV cells) creates safety hazards for workers as well as air and water pollution. Manufacturing power plant components and PV cells, not to mention the construction of generating facilities, entails various other risks to human health and the environment. Fossil-fueled, nuclear and concentrated solar power all use large amounts of water. Fossil-fueled combustion discharges pollutants to the air, produces water effluent and, in the case of coal combustion, generates solid wastes (coal ash). Hydroelectric


\textsuperscript{100} See EIA LCOE Estimates, \textit{supra} note 70, at 6.


\textsuperscript{102} For a source-by-source overview of these externalities, and the regulatory regimes governing them, see generally BOSELLEMAN ET AL., \textit{supra} note 37.
facilities interrupt fish migration routes, flood land, change water chemistry, and interrupt scenic vistas, as do wind farms. The list goes on.

Here, we summarize the externalities of electricity generation that produce the most salient and direct harms to human health and the environment. Of course, many of these harms are better conceived as risks, characterized by a predicted magnitude of harm multiplied by the probability that the harm will occur. Thus, researchers can conduct risk assessments of the adverse health impacts resulting from the air emissions associated with fossil fuel combustion; or characterize the water quality risks associated with the discharge of heat in effluent from thermal power plants. For those uncertain harms, there is often a gap between risk as assessed mathematically, and risk as perceived by stakeholders, a topic we examine in more detail in Part II.

First, it is well established that air emissions from fossil-fueled combustion entail significant risks to health and the environment. Coal combustion, in particular, produces significant harm to public health by emitting carbon dioxide (CO₂), the most common greenhouse gas, and nitrogen oxides (NOₓ), precursors of both acid rain and ground-level ozone (smog); so does natural gas, though in smaller amounts. In addition, coal combustion is a major source of emissions of (a) sulfur dioxide (SO₂), a precursor of acid rain, (b) particulate matter (PM), an inhalation hazard, and (c) mercury (Hg), ingestion of which poses a risk to neurological development. Methane—the primary component of natural gas—is itself a greenhouse gas far more potent than CO₂. Indeed, even though coal combustion emits twice the carbon dioxide of natural gas combustion, there is an ongoing scientific debate over whether coal-fired power or natural gas-fired power produces more GHG emissions over its full life cycle. Natural gas, however, produces a tiny fraction of the deadly PM emitted by coal combustion. Of course, EPA regulates all of these emissions, at least to some extent, under the Clean Air Act, though its GHG emissions regulation is neither finally set nor fully implemented.

Second, coal-fired and nuclear power production entail particularly thorny waste disposal issues. For coal-fired power the problem is coal combustion residuals, commonly called fly
ash, a high-volume waste the storage of which has resulted in several high-profile spills of toxic ash into rivers over the last decade, triggering an EPA decision to regulate coal ash storage and disposal under the Resource Conservation and Recovery Act. For nuclear power the problem is spent fuel and other radioactive wastes. These include low-level wastes, which are produced in relatively high volumes but which pose less danger to human health and the environment; and high-level wastes, especially the used nuclear fuel itself, which are currently being stored across the country in spent fuel pools or canisters. Both are highly regulated, but they have generated decades-long political and legal conflicts.

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As is evident from the discussion above, the three attributes in our framework—cost, reliability/flexibility, and externalities—are not uniformly distributed amongst the fuel sources for electricity. We turn now to a diagnostic account of the theory and practice of markets and regulation. This discussion helps situate the interaction of our three attributes within the economic literature, and it also suggests reasons why the electricity markets have difficulty minimizing cost while also maximizing reliability and minimizing negative externalities.

D. Markets: Theory and Practice

The under-supply of a sufficiently reliable and green power supply is a frequent lament in energy policy circles. Economic theory tells us that a well-functioning competitive market will maximize social net benefits, thereby providing society with a generation mix that balances cost, reliability, and externalities in a way that maximizes our collective utility. According to that

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111 When coal is burned for electricity generation, it creates both “fly ash”—the PM that is collected in pollution control equipment under the CAA—and “bottom ash”—the heavier ashes that are too big to be airborne and that are collected through the bottom of coal furnaces. It can contain a variety of heavy metals like lead, arsenic, and chromium. Spence & Hammond, supra note 109, at 472-73.


115 For an overview, see Spence & Hammond, supra note 109, at 486-87.


117 More specifically, such market will produce a distribution of goods that is Pareto optimal, in that no other distribution of goods can make one or more members better off without making one or more members worse off. See GEORGE C. HOMANS & CHARLES CURTIS, JR., AN INTRODUCTION TO PARETO 277-81 (1934) (explaining Pareto’s ideas on collective utility).
view, regulation ought to be aimed at getting prices “right” and otherwise creating conditions that mimic textbook competition.\(^\text{118}\) An alternative view places less faith in the ability of markets to produce socially optimal outcomes, and insists on a role for government intervention in markets to correct certain kinds of market failures.\(^\text{119}\)

In particular, many economists prescribe getting prices right as the solution to electric reliability problems. More specifically, some economists worry that in competitive wholesale markets, prices based on marginal costs will not attract sufficient investment in new capacity—referred to as the “missing money” problem.\(^\text{120}\) The reason that money is missing,” they say, is because consumers are insulated from the movement of wholesale prices by fixed-price retail contracts or tariffs, and because many wholesale markets operate under price caps imposed by regulators.\(^\text{121}\) In a perfect world, both wholesale and retail power prices would fluctuate freely and in real time, allowing both supply and demand to respond to price changes. Temporary price spikes would induce immediate demand reductions, and ultimately, lower prices; if not, sustained high prices would provide a sufficient reward for investment in adequate generation resources, ensuring reliability.\(^\text{122}\)

However, even where smart meters would enable retailers to offer dynamic pricing, it has remained elusive, notwithstanding that numerous pilot studies have demonstrated its benefits.\(^\text{123}\) Many consumers seem to prefer the security of fixed-price contracts, fearing downside risks and failing to appreciate the possibility of saving money in the long run.\(^\text{124}\) This loss aversion dynamic may be even more powerful for prospective investors in power plants, for both logical and behavioral reasons.\(^\text{125}\) Economists describe the problem as one of “asset specificity.” In a competitive market, when a firm’s assets are constructed at a particular location for a particular purpose, that firm faces the risk that its contractual counterparties (those from whom it buys or to whom it sells) will act opportunistically, taking advantage of the firm’s lack of alternative options to “hold up” the firm on price.\(^\text{126}\)

\(^\text{118}\) See generally LYNN KEISLING DEREGULATION, INNOVATION, AND MARKET LIBERALIZATION: ELECTRICITY RESTRUCTURING IN A CONSTANTLY EVOLVING ENVIRONMENT (2008) (conceptualizing electricity markets as complex adaptive systems in which price signals will stimulate innovation and create value).

\(^\text{119}\) See e.g., Boyd, supra note 20, at 1620 (conceptualizing electricity markets at “common, collective enterprise of building and elaborating the institutions, regulatory structures, and business models that will be necessary to realize a low-carbon future”).


\(^\text{121}\) See id. (providing examples); Pierce, supra note 66, at 468-77 (canvassing state restructuring experiences).


\(^\text{124}\) This notion finds ample support in the behavioral psychology literature, which explains that the fear of loss invokes the emotional part of the brain, leading people to pay to avoid downside risk. Antoine Bechara, et al., The role of the amygdala in decision-making, 985 ANN. N.Y. ACAD. SCI. 356 (2003); Antoine Bechara et al., Deciding advantageously before knowing the advantageous strategy, 275 SCI. 1293 (1997).

\(^\text{125}\) For a simple explanation of the behavioral psychology risk aversion literature, and its impacts on investment decisions, see JAMES MONTIER, BEHAVIOURAL INVESTING: A PRACTITIONERS GUIDE TO APPLYING BEHAVIOURAL FINANCE 447-52 (2007).

Power plants are characterized by asset specificity: they are often capital intensive, geographically immobile investments. In these situations, it might be dangerous to assume that arms-length transactions in the market will produce more efficient outcomes than vertical integration would have. One might therefore expect risk-averse investors to be more reluctant to invest in power plants in competitive electricity markets, and for this dynamic to be particularly strong for especially long-lived investments with especially large up-front costs, such as nuclear (and to a lesser extent, coal-fired) power plants. Indeed, energy consultants contend that this dynamic is accelerating the reduction in fuel diversity, exacerbating grid reliability problems. A future grid consisting mostly of gas-fired and renewable power (the only technologies experiencing growth) poses reliability challenges for grid operators. Integrating intermittent sources like wind and solar on a larger scale makes grid balancing more difficult. Gas-fired plants can back up wind because they can ramp efficiently, but they face their own reliability challenges: they cannot store fuel on site, are at the mercy of pipelines for supply, and natural gas prices have tended to be more volatile than fuel prices for any other generation source. In sum, the combination of incentives posed by the markets as they currently operate may decrease reliability over time.

Markets also struggle with pricing externalities, and the economics literature on environmental externalities has long recognized pollution as a kind of market (or pricing) failure. That literature goes back to Arthur C. Pigou, and generally endorses pollution taxation as the most efficient way to internalize environmental externalities, with marketable permits as a second-best alternative. The Coase Theorem challenged the Pigovian prescription by arguing that governments are unlikely to get taxation levels right; instead it posits that if property rights are assigned to conflicting parties, they will negotiate an outcome more likely to maximize social benefits. Others have been skeptical of market solutions; Garrett Hardin’s famous “tragedy of the commons” analysis offered government regulation as the solution to such problems.


127 Noting that asset specificity was the norm in the electricity industry, Paul Joskow argued prior to restructuring that reliance on anonymous spot market transactions to supply electricity is likely to fail “because the sinking of relationship-specific investments transforms a large numbers bargaining situation into a small numbers bargaining situation ex post,” creating opportunities for buyers or sellers to extract rents from the other and a consequent disincentive to invest in capacity. Joskow, supra note 126, at 123-25.


129 ARTHUR C. PIGOU, THE ECONOMICS OF WELFARE 185-226 (1920 & AMS Press 1978). Pigou is commonly credited with providing the first argument in favor of pollution taxes to force polluters to internalize pollution costs they would otherwise shift to society.


131 Coase’s conclusion was based on some stylized assumptions, including that the transaction costs of negotiating were zero. Ronald H. Coase, The Problem of Social Cost, 3 J.L. & ECON. 1 (1960).

132 Garrett Hardin, The Tragedy of the Commons, 162 SCI. 1243, 1247 (1968); see also Coase, supra note 131 (noting unrealistic nature of assumption that transaction costs of bargaining to a solution are zero, and that it “is normally the case [that] a large number of people are involved and in which therefore the costs of handling the problem through the market or the firm may be high”).
In practice, American policymakers have historically eschewed market incentives as well as private litigation for resolving pollution problems. Instead, prescriptive and proscriptive rules have been the norm—what most economists refer to, somewhat derisively, as command-and-control regulation. Most of the CAA’s approach to emissions from electricity generation falls into this category, as does the Nuclear Regulatory Commission’s (NRC’s) licensing regime for nuclear power plants. The seemingly intractable difficulty of environmental law is that these pollutant- and industry-specific regimes represent ad hoc responses to the externality problem, producing neither socially optimal pollution levels nor a level playing field among generators competing in wholesale electricity markets. For example, various studies reveal coal combustion to produce negative social net benefits, imposing large mortality, morbidity, and environmental costs on society from non-GHG air pollutants alone. One study estimated such costs at $53 billion per year, compared to less than $1 billion per year for natural gas. Thus, numerous sources argue that the regulated levels of air emissions permitted by the CAA for coal-fired power are too high. Nuclear and renewables, of course, emit none of those same pollutants.

In sum, the legal landscape for electricity stitches together a mix of market-based and regulatory approaches. The flaws in each have contributed to the electricity market’s failure to maximize cost, reliability, and the internalization of environmental harm. Further, the quickly changing markets and concomitant push for a greener grid have placed a marked strain on the traditional regulatory contract. The story of nuclear power provides a cogent example.

II. Nuclear Power in the Marketplace

In this Part, we consider how the nuclear licensing regime affects the competitiveness of nuclear power in modern electricity markets. After setting forth an overview of the federal regulatory scheme, we develop an account of the nuclear risk premium and show how it relates to the story of nuclear power historically and today. With that analysis in place, we can develop a concrete narrative of how the regulatory contract is increasingly strained in the marketplace.

A. Federal Nuclear Power Regulation

133 The major exceptions are the acid rain program enacted by Congress in 1990, which employs a marketable permit regime to effect reduction in sulfur dioxide emissions, and the use of renewable energy credits in many state RPS programs. See BOSSelman ET AL., supra note 37, ch. 5.
134 See infra Part II.A. (describing scheme).
135 Nicholas Z. Muller et al., Environmental Accounting for Pollution in the United States Economy, 101 AM. ECON. REV. 1649 (2011); see also sources cited supra note 103 (comparing life-cycle costs of various fuels).
136 Id. at 1669.
138 Muller et al. supra note 135, at 1669.
As noted in Part I, nuclear power faces very high capital costs and low fuel costs. It is a dependable, if not entirely flexible, source of power to the grid. In these ways, it is similar to coal-fired power, the other traditional base load source of electricity. However, nuclear power produces far fewer externalities than coal-fired power. Indeed, the existing nuclear regulatory regime has minimized such externalities far more effectively than environmental regulation does for nuclear power’s base load competitors.\textsuperscript{139} Congress and the nuclear agencies developed this regulatory regime, however, against the implicit assumption that the traditional regulatory contract would make this regime economically feasible.

Beginning in 1946, Congress gave the Atomic Energy Commission (AEC) “decisive control” over the entire field of nuclear energy.\textsuperscript{140} This authority included both military and civilian nuclear energy, a lineage that even today contributes to negative risk perceptions of nuclear power and mistrust of AEC’s successor agency, the NRC.\textsuperscript{141} Intent on emphasizing civilian nuclear power development, Congress shifted AEC’s mandate in 1954, and the agency’s primary policy mission became facilitating the emergence of the entire civilian nuclear power industry.\textsuperscript{142} Nonetheless, most of the American fleet of commercial reactors commenced construction in the 1960s and 70s, a period in which the cold-war threat of nuclear annihilation loomed in the public consciousness. As described above, this was also a period in which cost-of-service ratemaking encouraged capital investment in generation and transmission.\textsuperscript{143}

\textsuperscript{139} See supra note 103 (collecting source). For purposes of this section, we focus primarily on externalities associated only with electricity generation and describe the regulatory scheme unique to nuclear power. Some externalities associated with nuclear power are regulated under the same regime as those associated with other thermal generation. For example, both nuclear power and fossil-fueled generation must comply with the Clean Water Act’s (CWA’s) intake water and point-source discharge requirements. National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities, 79 Fed. Reg. 48,300 (Aug. 15, 2014). Air emissions for nuclear power plants, however, are handled under the NRC licensing regime, while those of fossil-fueled plants are subject to the CAA. See Richard Goldsmith, Nuclear Power Meets the 101\textsuperscript{st} Congress, A “One-Act” Comedy: Regulation of Nuclear Regulatory Commission Licensees Under the Clean Air Act, 12 VA. ENVTL. L.J. 103 (1992). Although new and proposed CAA regulations seek to reduce air-emission externalities of fossil-fueled power generation, those externalities persist and are not present for nuclear generation. See Muller et al. supra note 135, at 1669 (explaining nuclear was omitted from analysis because it does not emit pollutants in question). Finally, some states require siting approval for all new generation, including environmental assessments and certificates of public convenience and necessity. Edison Elec. Inst., STATE GENERATION AND TRANSMISSION SITING DIRECTORY (Oct. 2013), available at http://www.eei.org/issuesandpolicy/transmission/Documents/State_Generation_Transmission_Siting_Directory.pdf.


\textsuperscript{143} See Harvey Averch & Leland L. Johnson, Behavior of the Firm Under Regulatory Constraint, 52 AM. ECON. REV. 1052, 1052 (1962) (arguing cost-of-service approach leads to overinvestment in capital); see also Leon Courville, Regulation and Efficiency in the Electric Utility Industry, 5 BELL J. ECON. & MGMT. SCI. 53 (1974) (demonstrating this effect for power plants). But see W. Davis Dechert, Has the Averch-Johnson Effect Been
The Atomic Energy Act (AEA) vests responsibility with NRC for licensing nuclear power plants and ensuring their “adequate safety.” \textsuperscript{144} The licensing process is thorough, strict and resource-intensive; it comprises site selection, design, and construction and operating phases. \textsuperscript{145} Applicants must perform environmental reviews as required by the National Environmental Policy Act (NEPA), \textsuperscript{146} as well as various generic rules NRC has issued over the years. \textsuperscript{147} Applicants must either be regulated public utilities or satisfy stringent financial qualifications to engage in the proposed activities, \textsuperscript{148} and at the beginning of operations, they must provide “reasonable assurances” that funds will be available for the plant’s eventual decommissioning—which typically involves creating a trust fund. \textsuperscript{149} In addition, operators must obtain the maximum amount of liability insurance that can be purchased on the market. \textsuperscript{150} Finally, operators must pay for waste management, typically storing it onsite. Until 2013, licensees made payments to the Department of Energy (DOE) pursuant to the Nuclear Waste Policy Act in anticipation of sending spent fuel and other high-level radioactive wastes to a deep geological disposal site in Yucca Mountain, Nevada. \textsuperscript{151} After development of Yucca Mountain stalled, the D.C. Circuit ordered DOE to stop collecting these funds, \textsuperscript{152} but operators are nevertheless responsible for the costs of managing spent fuel onsite during operation as well as after decommissioning. \textsuperscript{153}

The process imposes still other costs on applicants and licensees that are not apparent from the outset. First, as plants age and licenses are renewed, replacement parts and upgrades will be needed. Second, during the lifetime of a license, NRC retains authority to modify or revoke the license if necessary to ensure adequate protection. \textsuperscript{154} Moreover, NRC may not

\textit{Theoretically Justified?}, 8 J. ECON. DYNAMICS & CONTROL 1, 16 (1984) (suggesting regulated firms under-invest in capital compared to unregulated firms).

\textsuperscript{144} 42 U.S.C. §§ 2131, 2232.

\textsuperscript{145} A prospective licensee may choose one of two procedural paths for obtaining the necessary licenses. The traditional path is set forth in 10 C.F.R. pt. 50; the newer path is set forth at id. pt. 52. \textit{See Bosslman et al., supra note 37, at ch. 7; see also Nuclear Info. Resource Serv. v. NRC, 969 F.2d 1169 (D.C. Cir. 1992) (en banc) (upholding part 52 licensing scheme).}

\textsuperscript{146} \textit{See 10 C.F.R. § 51.20 (listing types of actions requiring EIS under NRC’s NEPA implementing regulations).}

\textsuperscript{147} \textit{See Balt. Gas, 462 U.S. at 101 (noting “administrative efficiency and consistency of decision” are benefits of such generic rules).}

\textsuperscript{148} On the history of the financial qualifications requirement, see Emily Hammond Meazell, \textit{Deference and Dialogue in Administrative Law}, 111 COLUM. L. REV. 1722, 1760-63 (2011); \textit{see also} Coal. for the Envt’ v. NRC, 795 F.2d 168, 170-73 (D.C. Cir. 1986) (detailing agency and court actions over time).

\textsuperscript{149} 10 C.F.R. § 50.75; \textit{see Pennington v. ZionSolutions LLC}, 742 F.3d 715, 716-17 (7th Cir. 2014) (detailing regulatory scheme).


\textsuperscript{152} Nat’l Ass’n of Regulatory Util. Comm’rs v. DOE, 736 F.3d 517, 521 (D.C. Cir. 2013).

\textsuperscript{153} For an overview of these costs, see U.S. GOV’T ACCOUNTABILITY OFFICE (GAO), GAO-15-141, SPENT NUCLEAR FUEL MANAGEMENT: OUTREACH NEEDED TO HELP GAIN PUBLIC ACCEPTANCE FOR FEDERAL ACTIVITIES THAT ADDRESS LIABILITY app. V (Oct. 2014) (showing capital costs in tens of millions and annual operating costs at $100,000 to $300,000 for operating sites and $2.5 million to $6.5 million at shutdown reactor sites).

\textsuperscript{154} 42 U.S.C. § 2232(a); \textit{see Carstens v NRC}, 742 F.2d 1546, 1557 (D.C. Cir. 1984) (emphasizing standard does not require zero risk); \textit{see also} Nader v. Ray, 363 F. Supp. 946, 954 (D.D.C. 1973) (rejecting “complete,” “entire,” or “perfect” assurance of safety).
consider costs when determining what constitutes adequate protection.\textsuperscript{155} Thus, NRC may unilaterally modify or add to existing licensed facilities’ requirements (known as “backfitting”)\textsuperscript{156} in order to assure adequate protection without a cost-benefit analysis.\textsuperscript{157} Thus, even after licenses are granted and operators have internalized the costs described above, operators remain open to costly, unpredictable modification requirements for the lifetime of their licenses.\textsuperscript{158} For example, following Fukushima, NRC considered a potential backfit modification estimated by the agency to require $15 - 30 million per reactor unit; industry argued the cost would be as much as twice that.\textsuperscript{159} The possibility of added costs introduces an important element of risk into nuclear investments.

When one considers the many costs associated with siting, constructing, operating, and decommissioning a nuclear power plant, one can see why the levelized costs for nuclear are so high.\textsuperscript{160} Simply stated, nuclear regulation requires owners of nuclear power plants to internalize more of their externalities than other sources of generation. Waste products provide an example. Coal’s CCRs contain a variety of heavy metals but are not regulated as hazardous wastes under the Resource Conservation and Recovery Act (RCRA).\textsuperscript{161} As explained in Part I, CCRs are generated at a pace of more than 100 million tons per year, and poor disposal practices have caused several catastrophic incidents.\textsuperscript{162} Spent nuclear fuel, on the other hand, must be contained in extraordinarily robust fuel pools or dry casks that are regulated under the same defense-in-depth principles underlying nuclear generation facilities themselves; this approach has an extremely impressive safety record.\textsuperscript{163} And as described above, for years operators have also paid into the Nuclear Waste Fund for ultimate disposal of spent nuclear fuel.

\textsuperscript{155} See Union of Concerned Scis. v. NRC (Concerned Scientists I), 824 F.2d 108, 114 (D.C. Cir. 1987) (“In setting or enforcing the standard of “adequate protection” that this section requires, the Commission may not consider the economic costs of safety measures.”).

\textsuperscript{156} 50 C.F.R. § 50.109.

\textsuperscript{157} If NRC determines that a particular course of action will lead to substantial enhancements beyond adequate protection, however, it will engage in a cost-benefit analysis. Union of Concerned Scis. v. NRC (Concerned Scientists II), 880 F.2d 552 (D.C. Cir. 1989) (upholding two-pronged approach to backfitting). NRC issued several backfit orders in response to lessons learned from the Fukushima disaster. \textit{E.g.}, Order Modifying Licenses With Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events, NRC EA-12-049 (Mar. 12, 2012) (making adequate protection finding); \textit{see also} NRC, Modified Hardened Venting Order, NRC EA-13-109 (June 6, 2013) (making substantial enhancements finding). \textit{See generally} Emily Hammond, Nuclear Power, Risk, and Retroactivity, -- \textit{VAND. J. TRANSNAT’L L.} -- (forthcoming 2015) (manuscript on file with authors) (evaluating NRC response to Fukushima and implications of backfitting rules).

\textsuperscript{158} This possibility was a source of concern early in the AEA’s history. See Dunlavey, supra note 140, at 331 (“Most of these powers over the licensee provide no compensation to him for interrupting his business.”).

\textsuperscript{159} GAO, GAO-15-98, NRC NEEDS TO IMPROVE ITS COST ESTIMATES BY INCORPORATING MORE BEST PRACTICES 3 (Dec. 2014). After industry complaints, GAO was asked to investigate and report on NRC’s cost estimate methods generally, and this particular estimate specifically. GAO concluded that the cost estimate “is not reliable because it did not fully or substantially meet any of the four characteristics of a reliable cost estimate.” \textit{Id.} at 15.

\textsuperscript{160} \textit{See supra} Part I.C.1. (presenting LCOE estimates).


\textsuperscript{162} \textit{See supra} Part I.C.1. (describing CCRs).

\textsuperscript{163} \textit{See} Final Rule, Continued Storage of Spent Nuclear Fuel, 79 Fed. Reg. 56,238 (Sept. 19, 2014) (finding reasonable assurances of safety of long-term spent fuel storage); \textit{id}. at 56,247 (presenting table showing no noticeable predicted environmental impacts associated with short- or long-term storage, in nearly every category considered); \textit{see, e.g.}, Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel app. E,
Decommissioning provides another example. Nuclear power operators must uniformly pay in advance for decommissioning costs that may occur more than sixty years in the future. By contrast, the experience of fossil-fueled and renewable power varies by state. In some states, generators seek permission to recover costs of decommissioning only once the decision to close a plant has been made. Others require that bonds be posted at some date near the expected life of the project; for example, the Oklahoma Wind Energy Development Act requires owners of wind energy facilities to provide evidence of financial security to cover decommissioning costs after the fifteenth year of operation. In these and other ways, nuclear power internalizes costs that other sources of generation frequently do not.

B. The Nuclear Power Risk Premium

We hypothesize that nuclear power’s price tag is higher than would be economically efficient because it includes what we refer to as a “nuclear risk premium.” Economists have provided estimates of the increased costs facing new nuclear construction stemming from uncertainty about the regulatory landscape, construction timetables, and future prices of competing energy fuels like natural gas. In addition, risk perception operates as an explanatory variable for understanding not only those increased costs, but also the robust licensing scheme described above. Scholars have documented that risk perception mechanisms can lead to inefficient levels of regulation. This sort of inefficiency is present in the nuclear power regime, further undermining its cost competitiveness in the wholesale market.

First, we note that risk theory incorporates three distinct concepts: assessment, perception, and mitigation. Risk assessment—sometimes called engineering risk—is a methodology leading to an understanding of the probability that a hazard will manifest and the magnitude of the expected harm. NRC uses probabilistic risk assessment (PRA) to evaluate

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164 See supra text accompanying note 149.
167 As used in economic assessments of nuclear power, the “nuclear risk premium” refers to the cost of uncertainty and relates to investor reluctance to invest in more nuclear power given regulatory, construction, and fuel mix uncertainties. See MIT STUDY (2009 Update), supra note 71, at 8. Our usage is slightly different in that it incorporates risk perception as an explanatory variable.
168 Id.
169 CASS R. SUNSTEIN, LAWS OF FEAR: BEYOND THE PRECAUTIONARY PRINCIPLE 69 (2005) (“regulators may end up engaging in extensive regulation precisely because intensive emotional reactions are making people relatively insensitive to the (low) probably that dangers will ever come to fruition”); STEPHEN BREYER, BREAKING THE VICIOUS CIRCLE: TOWARD EFFECTIVE RISK REGULATION 3-29 (1993) (arguing various defects lead to irrational regulation).
risks associated with nuclear reactors.\textsuperscript{171} For example, its first study of this nature was issued in 1975 and considered accident risks based on the frequency of initiating events and their expected consequences.\textsuperscript{172} Following the Three Mile Island (TMI) accident, NRC began developing and applying increasingly rigorous methods of risk assessment and explicitly committed to quantitative risk assessment methods.\textsuperscript{173} The NRC’s part 52 licensing procedures require applicants for design certifications and combined licenses to perform a PRA and provide supporting analyses.\textsuperscript{174}

Risk mitigation—reducing the magnitude or likelihood of an anticipated hazard—is a fundamental goal of the licensing regime.\textsuperscript{175} NRC’s risk mitigation philosophy is captured in the term “defense-in-depth,” a notion that encompasses redundancy and contingency planning\textsuperscript{176} and implies multiple layers of preventative, mitigation, and emergency preparedness measures.\textsuperscript{177} More specifically, nuclear reactors are designed and constructed using assumptions about the types of hazards that must be mitigated. This analysis uses the concepts of “design-basis events” and “beyond-design-basis events.”\textsuperscript{178} The design-basis concept requires facilities to be designed with safety systems in place to address both anticipated operational events, and accidents.\textsuperscript{179} For example, seismic risks and flooding are two hazards contemplated by the design basis.\textsuperscript{180} Second, beyond-design-basis events are informally equated with safety enhancements, that is, requirements beyond adequate protection that would be mandated only if their benefits outweighed their costs.\textsuperscript{181} As new information is gleaned, NRC can use backfit analysis. Notwithstanding the quantitative engineering methodologies that underlie risk assessment, the verbal formulation described above it familiar to legal jurisprudence, as demonstrated most famously by the Hand Formula. See United States v. Carroll Towing Co., 159 F.2d 169 (2d Cir. 1947).

\textsuperscript{171} See NRC FACT SHEET, PROBABILISTIC RISK ASSESSMENT (Oct. 2007) (explaining that PRA seeks to quantify discrete risks as well as how those risks interact in a complex system).

\textsuperscript{172} NRC, REACTOR SAFETY STUDY: AN ASSESSMENT OF ACCIDENT RISKS IN U.S. COMMERCIAL NUCLEAR POWER PLANTS, WASH-1400 (Oct. 1975).


\textsuperscript{174} E.g., 10 C.F.R. §§ 52.47(23); 52.79(48).

\textsuperscript{175} This discussion focuses on the design and construction aspects of mitigating nuclear safety risks. However, these technological risk mitigation techniques are only part of the range of risk mitigation approaches relevant to this sector. Insurance, for example, is also considered a risk mitigation measure. See Hank Jenkins-Smith & Howard Kunreuther, Mitigation and Benefits Measures as Policy Tools for Siting Potentially Hazardous Facilities: Determinants of Effectiveness and Appropriateness, 21 RISK ANALYSIS 2 (2001) (providing additional examples); Paul Kleindorfer & Howard Kunreuther, The Complimentary Roles of Mitigation and Insurance in Managing Catastrophic Risks, 19 RISK ANALYSIS 727 (1999) (discussing cushions and insurance).


\textsuperscript{177} Id. at 25. But as the NRC’s post-Fukushima Near-Term Task Force for Lessons Learned (NTTF) determined, the defense-in-depth and PRA approach are not efficiently combined in NRC’s regulatory scheme. See NRC, NEAR-TERM TASK FORCE, RECOMMENDATIONS FOR ENHANCING REACTOR SAFETY IN THE 21ST CENTURY: THE NEAR-TERM TASK FORCE REVIEW OF INSIGHTS FROM THE FUKUSHIMA DAI-ICHI ACCIDENT 21 (July 12, 2001) [hereinafter NTTF Report]. Indeed, a major component of the NTTF’s recommendations was to completely overhaul the regulatory framework, to combine risk assessment and defense-in-depth “more formally.” Id.; see also id. at 22 (“The Task Force recommends establishing a logical, systematic, and coherent regulatory framework for adequate protection that appropriately balances defense-in-depth and risk considerations.”).

\textsuperscript{178} Id. at 15.

\textsuperscript{179} Id.

\textsuperscript{180} Id.

\textsuperscript{181} Id.
orders to require risk mitigation updates, prompting the regulatory uncertainty described above.\textsuperscript{182}

The final component of risk theory—risk perception—is our focus here. Risk perception deals with the many mechanisms by which the human brain perceives, understands, predicts, and responds to risk. Risk theory suggests a strong likelihood that perception imposes costs on nuclear power disproportionately in relation to other electricity fuel sources. One of the most straightforward ways to understand this disproportionality is by reference to research developing the “psychometric paradigm.”\textsuperscript{183} The psychometric paradigm uses statistical techniques to organize risk perceptions according to two variables.\textsuperscript{184} The first is the extent to which a risk is dreaded—that is, “catastrophic, hard to prevent, fatal, inequitable, threatening to future generations, not easily reduced, increasing, involuntary and [personally] threatening.”\textsuperscript{185} The second variable relates to the familiarity of a risk—that is, its “observability, knowledge, immediacy of consequences and familiarity.”\textsuperscript{186} Nuclear technology—power, waste disposal, and uranium mining—features prominently among the high-dread, low-familiarity risks.\textsuperscript{187} By contrast, examples of low-dread, high-familiarity risks are bicycles, shock from electric appliances, recreational boating, chainsaws, and trampolines.\textsuperscript{188}

The higher a risk scores on the “dread” axis, the more people tend to want strict regulation in hopes of reducing the risk.\textsuperscript{189} And indeed, the nuclear licensing scheme is one of the strictest in the United States,\textsuperscript{190} both in terms of the substantive requirements for adequate protection, and in terms of the procedural requirements associated with obtaining licenses. The

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\textsuperscript{182} E.g., Hammond supra note 157 (describing rulemaking and backfitting orders following Fukushima); NTTF Report, supra note 177, at 16 (describing backfitting following September 11, 2001 terrorist attacks); id. (describing backfitting following TMI accident).

\textsuperscript{183} Note that a variety of risk perception mechanisms provide insights into nuclear power; we highlight the psychometric paradigm for its demonstrative usefulness. One of the most important alternative accounts for risk perception generally is cultural cognition theory (CCT), which attempts to account for variations among individuals by grouping them into cultural worldview. For example, France is far more accepting of nuclear power than the United States. Paul Slovic et al., Nuclear Power and the Public: A Comparative Study of Risk Perceptions in France and the United States, in CROSS-CULTURAL RISK PERCEPTION: A SURVEY OF EMPIRICAL STUDIES 55 (2000). The French, however, are more likely to hold hierarchical worldviews than individualistic Americans. Id. at 51. Thus, they are both more accepting of the risks associated with nuclear power, and more comfortable with the ability of elite experts to manage those risks. Id. at 87-90, 93-94, 98; see also MARY DOUGLAS & AARON WILDAVSKY, RISK AND CULTURE: AN ESSAY ON THE SELECTION OF TECHNICAL AND ENVIRONMENTAL DANGERS (1982) (presenting early work on cultural theory). Other risk perception mechanisms relevant to low-probability, high-consequence risks like nuclear power are collected in SUNSTEIN, supra note 169 (describing the availability heuristic, probability neglect, loss aversion, system neglect, and affect, among others).

\textsuperscript{184} Paul Slovic, Perception of Risk, 236 SCIENCE 280, 281 (1987).


\textsuperscript{186} Id.

\textsuperscript{187} Slovic, supra note 184 at 236.

\textsuperscript{188} Id.

\textsuperscript{189} Id. at 283.

substantive requirements are addressed above, but the procedural requirements are worth emphasizing as well. To illustrate the point, consider the famous administrative-law decision, Vermont Yankee,191 which was borne of public opposition to nuclear power and the D.C. Circuit’s concern that agencies were not taking seriously the public protection mandates of their organic statutes.192 Imposing stricter procedures on agencies was viewed by some as an appropriate way for courts to police what they perceived to be inadequate risk regulation.193 Vermont Yankee clamped down on courts’ use of this method,194 but those who oppose nuclear power (and other dread risks) are motivated to persistently seek more formalized procedures, which generally take more time than less formal approaches, notwithstanding that the existing procedures are already highly formalized and costly.195

In addition to attracting substantively and procedurally complex regulatory schemes, dread risks are also particularly susceptible to “punctuating events,” that is, spectacular, high-profile, low-probability events that are processed by the brain as representative of the risks posed by a technology generally.196 After Three Mile Island and Chernobyl, no new nuclear reactors were constructed in the United States for over thirty years, and worldwide construction likewise declined sharply. The safety questions and backfitting orders raised by these events, moreover, contributed to the notorious construction delays for plants in progress. And finally, public opposition to nuclear power grew significantly, contributing to regulatory delays and a lack of political support for the technology. To be clear, we note that punctuating events can highlight needed and appropriate changes.197 But they can also prompt knee-jerk responses from elected officials, regulators, and the public that contribute to overregulation and regulatory uncertainty.198 With longstanding and strong opposition finding fresh motivation with each

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192 This history is recounted in Emily Hammond Meazell, Super Deference, the Science Obsession, and Judicial Review as Translation of Agency Science, 109 Mich. L. Rev. 733, 758-59 (2011) [hereinafter Hammond, Super Deference].
193 This use of procedure dates at least to the origins of the APA. See Martin Shapiro, APA: Past, Present, & Future, 72 Va. L. Rev. 447, 453 (1986); Sidney A. Shapiro, A Delegation Theory of the APA, 10 Admin. L.J. 89, 98 (1996) (adoption of the APA “signaled that broad delegations of power and combined functions would be tolerated as long as they were checked by more extensive procedures.”). see also McNollgast, The Political Origins of the APA, J.L. Econ. & Org. 180, 181 (1999) (“By reducing administrative discretion, formal procedures create transaction costs that increase the time and resources needed to change policy.”).
194 But see Jack Beerman & Gary Lawson, Reprocessing Vermont Yankee, 75 Geo. Wash. L. Rev. 856, 858-59 (2007) (collecting literature arguing courts continue to impose unwarranted obligations on agencies).
195 See Citizens Awareness Network, Inc. v. NRC, 391 F.3d 338, 343 (1st Cir. 2004) (describing history). Other features of regulatory design, such as redundancy and complexity, likely also relate to risk perceptions, but a full account is beyond the scope of this paper. See Jason Marisam, Duplicative Delegations, 63 Admin. L. Rev. 181, 224 (2011) (“bureaucratic redundancies are most often worthwhile when the redundant agency provides a significant benefit by safeguarding against high-magnitude harm.”).
196 For an overview of such issues, see generally Risk, Media and Stigma: Understanding Public Challenges to Modern Science and Technology (2001). See also Paul Slovic, Perception of Risk, 236 Sci. 280, 283 (1987) (describing enormous costs TMI imposed on society in terms of stricter regulation and increased opposition to nuclear power, despite that it caused relatively little actual harm).
197 See Coast Anti-Pollution League v. NRC, 690 F.2d 1025, 1028 (1st Cir. 1982) (describing how Three Mile Island illustrated need for emergency planning for areas around nuclear power plants); see generally NTTF Report, supra note 177 (describing recommendations in response to Fukushima).
198 SUNSTEIN, supra note 169, at 206; Slovic, supra note 196, at 283-84.
punctuating event, agency and industry plans in these areas tend to encounter “extensive delay and escalating costs that have been widely regarded as attributable to public opposition.”  

This form of cost uncertainty is extraordinarily difficult to quantify, but it is certainly present for nuclear power. Of course, perceived risks do encompass some actual risks, which ought to be and are mitigated by the robust licensing scheme described above. In addition, some of the byproducts of dread serve other functions. Heightened agency procedures, for example, are a response to actual public concern, and in that way serve important ideals that are at the core of government legitimacy. What this discussion of risk perception illustrates, however, is that because nuclear power has unique risk attributes, it bears costs that other fuel sources do not bear. To some extent, this means that nuclear power most fully internalizes its costs. But it is also means that the role of risk perception cannot be ignored in considering how different electricity fuel sources and markets interact.

C. A Dynamic Account of the Nuclear Risk Premium

From the preceding discussion it is starting to become apparent how nuclear power went from “too cheap to meter” to uncompetitive on today’s wholesale markets. Nuclear power plants in operation today were constructed on the assumption that electricity demand would skyrocket, during a period when natural gas-fueled electricity generation was banned due to shortages, oil prices were escalating, and national security was a prominent concern. The traditional regulatory contract, complete with rate recovery of costs plus a fair return, was the norm. And it appeared both that large amounts of capacity would be needed to meet projected demands, and that coal and nuclear generation were so cost-superior to oil and natural gas

202 Of course, nuclear power was never actually “too cheap to meter.” Some commentators have argued that the phrase itself was essentially propaganda, lacking endorsement even from nuclear supporters. See VACLAV SMIL, ENERGY MYTHS AND REALITIES: BRINGING SCIENCE TO THE ENERGY POLICY DEBATE at 31-32 (2010) (attributing “too cheap to meter” to 1954 speech by AEC Chairman Lewis L. Strauss to National Association of Science Writers, and suggesting Strauss may have been referring to fusion); id. at 32 (describing 1955 journal entry of David E. Lilienthal, stating nuclear development “is characterized more by salesmanship, propaganda, and overzealousness than sense.”).  
203 Expectations were for more than a 7% increase annually. EIA, NUCLEAR PLANT CANCELLATIONS: CAUSES, COSTS, AND CONSEQUENCES 7 (1983).  
generation that the latter two generation sources should be retired.\textsuperscript{206} In other words, nuclear power appeared to be the best option for consumers.

Yet the projections that spurred significant investments in nuclear power failed to come to fruition. Demand did not increase as expected, deregulation of natural gas led to dramatically reduced prices, and the oil market did not behave as forecast.\textsuperscript{207} Nuclear power plants turned out to be relatively expensive investments. Further, these developments coincided with the TMI accident as well as the Chernobyl disaster, which contributed to negative perceptions and prompted additional regulatory action.\textsuperscript{208} Ultimately, nuclear construction costs ran as much as ten times what had been predicted, the timeframe for completion stretched to an average of twelve years, and utilities began canceling partially completed plants.\textsuperscript{209} There is some debate about the reasons for the significant disparities between projected and actual historical costs.\textsuperscript{210} Most accounts, however, cite regulatory delays, redesign requirements, and poor construction management and quality control.\textsuperscript{211} Ultimately, utilities encountered great difficulties when they found that they could not necessarily recover from their ratepayers (a) the full costs of completed plants,\textsuperscript{212} or (b) the costs of canceled plants.\textsuperscript{213}

Consider, for example, \textit{Duquesne Light Co. v. Barash},\textsuperscript{214} which involved the issue of rate recovery for the costs associated with canceled nuclear plants. There, the Supreme Court upheld a state statute requiring rates to be set without consideration of expenditures for plants that were planned but never built.\textsuperscript{215} The story was typical: several utilities planned to construct seven nuclear power plants, but determined after the Arab oil embargo and TMI that the plants should be cancelled.\textsuperscript{216} One utility’s share of preliminary construction costs exceeded $35 million, and it sought permission from the state PUC to recoup those costs in its rates by amortizing them over a ten-year period.\textsuperscript{217} Following an investigation, an administrative law judge determined that the expenditures, and the ultimate cancellation, were reasonable and prudent at the time made.\textsuperscript{218} But an intervening state statute required that construction costs could be included in rates only when facilities became “used and useful.”\textsuperscript{219}

Acknowledging the regulatory contract, the Court began by noting that public utilities are bound by a statutory duty to serve the public notwithstanding their ownership by private

\textsuperscript{206} Pierce, \textit{supra} note 205, at 502.

\textsuperscript{207} See id. at 502-03 (describing outcome of these and other forecasts).

\textsuperscript{208} See supra. Notably, most construction also took place during the Cold War, when worries of nuclear annihilation were prominent in the minds of many citizens; it was easy to link the imagery of nuclear weapons to nuclear power plants. See Dorothy Nelkin, \textit{Anti-Nuclear Connections: Power and Weapons}, 37 BULL. ATOMIC. SCI. 36, 38-39 (1981) (linking anti-nuclear power and anti-nuclear proliferation movements).

\textsuperscript{209} See Pierce, \textit{supra} note 205, at 504-05 (describing events and collecting sources).

\textsuperscript{210} MIT Study, \textit{supra} note 71, at 38. Notably, European reactor construction costs also significantly exceeded projections. \textit{Id.}

\textsuperscript{211} For example, the part 50 licensing process enabled contentions to be raised and re-raised at each licensing phase, contributing to numerous delays. Boseeelman et al., \textit{supra} note 71, ch. 7; see also MIT Study, \textit{supra} note 71, at 38 (describing reasons).

\textsuperscript{212} See Pierce, \textit{supra} note 205, at 511-17 (describing state regulatory treatment of completed plants).

\textsuperscript{213} \textit{Id.} at 517-20 (describing state regulatory treatment of canceled plants).


\textsuperscript{215} \textit{Id.} at 302.

\textsuperscript{216} \textit{Id.}

\textsuperscript{217} \textit{Id.} at 303.

\textsuperscript{218} \textit{Id.}

\textsuperscript{219} \textit{Id.} at 303-05.
The Court recognized that the rate order may not jeopardize the financial integrity of a company, or leave it with insufficient operating capital, or unable to raise future capital. However, in this case, the denied costs represented only a small portion of the utility’s overall rate base, and leaving the utility with a sufficient rate of return, and the Court refused to intervene.

Decisions like *Duquesne* undermined investors’ expectation that the costs involved in obtaining a nuclear operating license would largely be borne by ratepayers. Cost recovery for completed plants, of course, had always been subject to certain limitations—most commonly, the requirement that an investment be prudent or that a facility be used and useful. Since investors expected that nuclear plants would be necessary to serve growing demand, they never considered the possibility that a “prudent” investment might be cancelled—that is, that it might never become “used and useful.”

1. Barriers to New Construction

The history of disappointed rate recovery expectations continues to dampen enthusiasm for new nuclear projects. In regulated states, investors have learned the painful lesson that cost recovery is not guaranteed. And in restructured states, there are even deeper issues. Cost recovery is not a feature of the landscape, and the “missing money” problem means that wholesale rates are unlikely to incentivize even needed new capacity. Asset specificity will further disincentivize large capital investment. Of the 100 reactors operating today, all had broken ground by 1977. The leveled cost estimates set forth in Part I implicitly reflect these concerns, which have only been exacerbated by subsequent punctuating events—most recently, the Fukushima disaster.

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220 Id. at 307.
221 Id. at 312.
222 Id. at 311-12.
223 Contributing to the uncertainty are examples to the contrary. See, e.g., Pennington v. ZionSolutions LLC, 742 F.3d 715, 717 (7th Cir. 2014) (typically decommissioning trusts are funded by charges to ratepayers); Yankee Atomic Elec. Co. v. United States, 73 Fed. Cl. 249, 251 (Fed. Cl. 2006) (referencing ratepayers’ bearing costs of spent fuel storage and amounts paid to Nuclear Waste Fund); Legis. Util. Consumers’ Council v. Pub. Serv. Co., 402 A.2d 626 (N.H. 1979) (upholding state PUC’s inclusion in rate base of construction work-in-progress to finance nuclear power plant construction); cf. Grand Council of Crees (of Quebec) v. FERC, 198 F.3d 950, 957 (D.C. Cir. 2000) (holding environmental challenge to FERC exercise of ratemaking authority outside statute’s zone of interests; noting environmental considerations are relevant “as the need to meet environmental requirements may affect the firm’s costs.”). For a case involving new nuclear construction, see *In re Georgia Power’s Application for the Certification of Unites 3 and 4 at Plant Vogt and Updated Integrated Resource Plan*, No. 27,800, 2010 WL 2647607 (Ga. Pub. Serv. Comm’n June 17, 2010).
224 See Pierce, supra note 205, at 511-13. Many jurisdictions also provide some recovery during construction. See, e.g., Mid-Tex Elec. Coop., Inc. v. FERC, 773 F.2d 327 (D.C. Cir. 1985) (discussing FERC’s history with two methods: allowance for funds used during construction (AFUDC); and construction work in progress (CWIP)).
225 MIT Study, supra note 71, at 38 (“the specter of high construction costs has been a major factor leading to very little credible commercial interest in investments in new nuclear plants”); cf. NUCLEAR ENERGY INST., WHITE PAPER, CONSTRUCTION WORK IN PROGRESS: AN EFFECTIVE FINANCIAL TOOL TO LOWER THE COST OF ELECTRICITY, at 3-4 (Feb. 2012) (describing importance of state CWIP legislation for nuclear power construction).
226 See supra Part I.D.I. (discussing these issues).
227 Id.
228 EIA, NUCLEAR REACTOR OPERATIONAL STATUS TABLES, NUCLEAR REACTOR CHARACTERISTICS AND OPERATIONAL HISTORY Tbl. 3 (Nov. 22, 2011).
229 See NTTF Report, supra note 177 (describing events).
Despite these developments, there has been some movement in new reactor construction, though to date new construction is limited to two traditionally regulated states—Georgia and South Carolina. This activity is attributable to several circumstances. First, all of the granted and pending license applications were filed in a period from 2007-09, when natural gas prices were high and the hydraulic fracturing boom had not yet taken hold. In addition, coal was increasingly under scrutiny for its GHG emissions, and Congress was considering a number of climate change bills that would have increased the cost of emitting GHGs.

Second, the Energy Policy Act of 2005 (EPAct 2005) included major incentives for new nuclear plants that were focused on lowering the risks for first movers. These incentives included regulatory risk insurance, which authorized DOE to enter up to six contracts with sponsors of new nuclear power. Under these contracts, the government promised to pay the principle and interest on debt, as well as extra costs incurred for purchasing replacement power due to licensing delays. Notably, this risk insurance covered agency delay as well as litigation expenses, regardless of the ultimately prevailing party. In this way, federal law aimed at least briefly at some of the risk-perception induced costs associated with nuclear power.

EPAct 2005 also included a nuclear production tax credit for the first 6000 MW of new nuclear capacity for the first eight years of operation. However, construction was required to begin by January 1, 2014 to meet eligibility requirements. Thus, only the four reactors currently under construction met these criteria. Finally, EPAct 2005 authorized loan guarantees for clean energy projects, under which the federal government can guarantee up to eighty percent of a nuclear plant’s estimated costs. To be eligible for such loans, applicants must have been granted a combined operating license from NRC. Thus, few applicants are eligible, and so far DOE has closed on a loan only for one project—the Vogtle project in Georgia. For this plant,

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230 See infra Part III.B.2. (describing state initiatives).
231 These are, respectively, the Southern Nuclear Operating Company’s Vogtle Units 3 and 4, and South Carolina Electric and Gas’s V.C. Summer Units 2 and 3. Note that TVA has also resumed construction of its Watts Bar Unit 2, which had been suspended in 1985. See NRC, WATTS BAR UNIT 2 REACTIVATION, http://www.nrc.gov/info-finder/reactor/wb/watts-bar.html (last visited Feb. 3, 2015). Eight applications for combined licenses are pending, some of which are for reactors in restructured states. NRC, COMBINED LICENSE APPLICATIONS FOR NEW REACTORS, http://www.nrc.gov/reactors/new-reactors/coll.html (last updated July 1, 2014). The pending applications are for units in Maryland (restructured), Michigan (restructured), Florida, Pennsylvania (restructured), Virginia, and Texas (restructured). Id.
234 See MIT Study (2009 Update), supra note 71, at 8-9 (discussing “risk premium” associated with nuclear and need to gain proven experience if premium is to be reduced).
236 The regulatory risk insurance was structured so that the first two licensed reactors were covered for 100% of these costs (with a $500 million limit), while the next four were covered at 50% (with a $250 million limit). See Final Rule, Standby Support for Certain Nuclear Plant Delays, 71 Fed. Reg. 46,306 (Aug. 11, 2006).
237 Id. at 46,308-09.
240 See GAO, STATUS OF DOE LOAN PROGRAMS, BRIEFING TO APPROPRIATIONS COMMITTEES 17 (Feb. 2013).
at least, the specter of unrecoverable cost overruns has been diminished. Prospective new entrants today, however, face the same hurdles as before.

2. Competing on the Markets

The discussion above helps explain why investors are reluctant to construct new nuclear plants, but it does not necessarily explain why existing plants are finding it so difficult to compete on the wholesale markets. Nuclear industry groups typically explain that low natural gas prices and policies giving preferences to renewables are to blame.241 But what does that really mean? With respect to low natural gas prices, recall that low fuel costs for generators translate to low short-run marginal costs and low bids into the spot markets.242 This is also true for renewables, which have zero fuel costs once installed, and which can bid lower prices to the extent they also generate RECs or benefit from production tax credits. But there is more to the story for nuclear power, as alluded to in Part I.

For fossil-fueled power, more fuel must be burned to increase the energy output of a plant; thus, those sources’ marginal costs are closely tied to the cost of fuel and the efficiency of the plant.243 But nuclear power depends on fuel that is loaded every eighteen to twenty-four months; this happens on a regularly scheduled basis and corresponds with intense unrelated maintenance activity.244 Small changes in output related to grid demand do not change this schedule or the fuel costs; with this understanding we can say that nuclear power’s short-run marginal costs are zero.245 Moreover, because nuclear plants need to run continuously, they bid into the market as “price takers,” meaning they will take the spot price, even if that price is negative.246 Recall, however, that firms need operating profits to cover their fixed costs. If, on average, a firm receives spot prices below its long-run average costs, the firm will not be profitable. For nuclear power, those costs include a highly trained workforce, backfits, upgrades, insurance payments, fuel management, and final waste disposal.247 In other words, the comprehensive regulatory scheme, which beneficially internalizes what for other fuels are externalities, also contributes to higher long-run average costs compared to other fuel sources. When spot market prices are low, nuclear power can become unprofitable. Indeed, several plants have closed for this reason,248 and many others appear to be at risk.249

242 See supra Part I.C.1.
243 id.
244 NUCLEAR ECONOMICS CONSULTING GROUP, NUCLEAR POWER & SHORT-RUN MARGINAL COST 2-3 (2014).
245 id. In a regulated state, the relevant calculation would include the cost of fuel averaged over the expected plant output for the one-and-a-half to two-year operating period. id. at 2.
246 id. at 4.
247 See supra Parts II.B. – C. (describing various costs).
D. Lessons Learned

The experience of nuclear power makes several points concrete. First, the regulatory contract, once a cornerstone of investor expectations and an assumption underpinning the nuclear regulatory regime, is now much more amorphous. Cost recovery for large capital projects seems uncertain or open to negotiation, rather than a boilerplate term. Second, the impact of new federal requirements is now felt differently in regulated states—where backfitting, for example, is still recoverable—as opposed to restructured states—where the same large costs cannot be recouped on the market. And finally, in the wholesale markets where only short-run marginal costs matter, the flaws predicted by economists are manifesting themselves in the reality of nuclear power. That is, the markets are blind to the costs nuclear power incurs to provide reliable base load and to internalize its environmental impacts. To be sure, many would argue that the atomic age should come to a close. But the stakes are high: as nuclear power is increasingly priced out of the market, scientists have observed corresponding increases in air pollution.\textsuperscript{250} The loss of this low-carbon source of generation is also of great concern, as the need for GHG mitigation grows increasingly urgent.\textsuperscript{251} And over time, there is a loss of diversity in fuel sources, putting corresponding pressure on reliability.

We have focused our discussion on nuclear power partly because it so clearly demonstrates how and why the markets fail to value important attributes for electricity. But the lessons learned have important ramifications for other grid resources. All else equal, price competition favors sources like coal that can shift more pollution costs to society, or sources like natural gas that do not face the large up-front capital costs and long construction times. This puts low-emission sources like nuclear and some renewables at a relative disadvantage. Nor are risk perception issues limited to nuclear power. For example, they are increasingly a motivating force behind significant opposition to smart meters—a key piece of technology that would enable dynamic pricing as well as demand response.\textsuperscript{252} These issues are also contributing to an increasing number of bans on hydraulic fracturing—which may impact the price of natural gas.\textsuperscript{253} Overall, there is much work to be done if we are to achieve an efficient, reliable, green grid.

III. Reforming the Regulatory Contract?


\textsuperscript{251} See Suzanne Waldman, Timeline: The IPCC’s shifting position on nuclear energy, BULL. ATOMIC SCIS. (Feb. 8, 2015), http://thebulletin.org/timeline-ipcc%E2%80%99s-shifting-position-nuclear-energy7975 (describing increasing note of urgency in Intergovernmental Panel on Climate Change (IPCC) reports regarding need to use all available low-carbon fuels, including nuclear power).

\textsuperscript{252} See Joel B. Eisen & Emily Hammond, Risk Perception and the Smart Grid (manuscript on file with authors) (citing examples).

Changes in electricity markets have exposed anachronistic features of the various regulatory regimes that now define the regulatory contract. This Part considers policy options that may ameliorate this divergence and help electricity markets better value clean and reliable electricity resources. Pursuing those policy options, however, implicates the matter of governance. The parties to the regulatory contract are no longer simply states and IOUs. Instead, state, regional, and federal actors are players in regulatory schemes that have only become more complex with the emergence of competitive markets. Thus, we take note of governance challenges first.  

A. Governance Challenges and the New Regulatory Contract(s)

Pursuit of the dual-visioned green and efficient grid has produced mismatches between rapidly evolving markets and governance institutions that cannot evolve as quickly. As described in Part I, parts of the market that were once within the control of state PUCs are, in some states, now controlled by regional, quasi-regulatory entities—namely, RTOs and ISOs. In other, more traditionally regulated states, PUCs retain control over prices and market entry. And some state PUCs must work with multiple RTOs as well as traditional regulated utilities, all within the state borders. Alongside this complex, multi-tiered electricity regulatory structure sits environmental law and its system of cooperative federalism, which continues to dominate the management of environmental externalities for air and water resources, largely in the same way as it has since the 1970s. With respect to climate change, however, states, local governments, and regional entities are taking their own initiatives to address issues left unresolved at the federal level. Overall, subnational institutions have filled the gap left by a gridlocked Congress. 

But as emphasized in Part II, source-specific federal law can exert a powerful effect on the relative competitiveness of different fuels. The example of nuclear power forcefully demonstrates the point with its strong and comprehensive regulatory regime for power plant licensing. Indeed, this regulatory scheme provides the benefits of a nearly complete treatment of nuclear’s possible negative externalities, but imposes high compliance costs, some of which

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254 These challenges are not new. See, e.g., Peter Huber, Electricity and the Environment: In Search of Regulatory Authority, 100 HARV. L. REV. 1002, 1002 (1987) (lamenting irretrievable fragmentation of regulatory authority over electricity).

255 See Hammond & Markell, supra note 201, at 355-56 (discussing cooperative federalism structure and its influence on development of environmental policy).


257 Nascent EPA efforts to regulate GHG emissions from power plants recognize as much. See Clean Power Plan, supra note 10, at 34,833 (emphasizing state flexibility).

258 Our focus has been electricity markets, but the experience of natural gas markets also demonstrates the point. See Phillips Petrol. Co. v. Wisconsin, 347 U.S. 672 (1954) (holding Natural Gas Act required FPC to regulate price of natural gas at the well head into interstate commerce); Richard J. Pierce, Jr., The Evolution of Natural Gas Regulatory Policy, 10 NAT. RESOURCES & ENV’T 53 (Summer 1995) (criticizing Phillips and tracing history of natural gas policy).

259 Hydroelectric licensing is similar in that the process is centralized in a federal agency, and preempts most state and local regulation. California v. FERC, 495 U.S. 490, 496 (1990); First Iowa v. Hydro-Elec. Coop. v. Fed. Power Comm’n, 328 U.S. 152, 174 (1946).
may be over and above efficient levels. This regime was created in the time of a strong regulatory contract, when nuclear plants did not compete directly with other generation sources on price. Ironically, the federal regulatory regime persists in the context of a system of market pricing that takes no notice of the added technical, safety, and environmental benefits that the current licensing provides.

Not only does law require some generation sources to internalize more of their environmental externalities than others, but states have come into increasingly frequent conflict with regional entities, the federal government, and each other over electricity market regulation. For example, states in the western half of the PJM market are in a perpetual battle with those in the eastern portion over a variety of cost-allocation issues. This is true despite an overarching federal structure; after all, FERC itself opened the markets, specified the requirements for RTOs and ISOs, and retains oversight authority. More and more frequently, however, this federal structure is challenged to delineate its jurisdictional lines, both respect to electricity markets and environmental law.

This much is clear: in electricity markets, federal law is not operating as a unified and unifying institution. Rather than viewing federal law as a failed effort at policy unification and market design, however, we can identify ways it has enabled shifts in thinking and experimentation elsewhere. First, there is much untapped potential within the existing discretionary authority of federal agencies—a point to which we return in the next section. Second, federal law has left significant gaps for state- and region-level institutional innovators. This observation is consistent with recent federalism law scholarship emphasizing that states are more than the mere experimenters seeking a common (often national) goal in new and different ways. Rather, in an increasingly ideologically polarized polity, each state is striving to shape the regulatory contract in its own way. More than that, policy entrepreneurs may now look to ideologically kindred states as venues within which to pursue their policy goals.

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260 See, e.g., Ill. Comm. Comm’n v. FERC, 756 F.3d 556, 558 (7th Cir. 2014) (describing competing interests and protracted litigation).
261 Freeman & Spence, supra note 20, at 52-55 (providing context).
262 See supra note 19 (collecting energy examples); United Air Reg. Util. Grp. v. EPA, 134 S. Ct. 2427 (2014) (upholding in part, and rejecting in part, EPA GHG regulations under CAA). Often, these conflicts divide along political party lines. For example, EPA is in frequent conflict with states controlled by Republicans during Democratic presidencies, and states controlled by Democrats during Republican presidencies. During the George W. Bush administration, states sued EPA over a variety of Clean Air Act issues. See e.g., Massachusetts v. EPA 549 U.S. 497 (2007) (states sought to force EPA to regulate GHG emissions); New Jersey v. EPA 517 F.3d 574 (D.C. Cir. 2008) (state challenging EPA’s approach to regulating mercury emissions). During the Obama Administration, states sued EPA over another set of Clean Air Act issues. See, e.g., EPA v. EME Homer Generation, L.P., 134 S. Ct. 1584 (2014) (states challenged EPA’s approach to regulating pollution transport); White Stallion Energy Ctr., LLC v. EPA, 748 F.3d 1222 (2014) (states challenged EPA’s approach to regulating mercury emissions); and.
264 See New State Ice Co. v. Liebman, 285 U.S. 262, 386-87 (1932) (Brandeis, J., dissenting) (“It is one of the happy incidents of the federal system that a single courageous state may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risk to the rest of the country.”).
265 See Bulman-Pozen, supra note 263, at 1082-83 (emphasizing states as arenas of partisan conflict, including conflict with federal actors, while implementing federal regulatory mandates).
266 Id. at 1116-22 (arguing that people identify with parties, and with states based upon the dominant party or ideology within the state).
This conception is descriptively helpful because it requires that we acknowledge multiple arenas for policy development, recognizing that ideological conflicts shape those developments. There is also a normative purpose in conceiving state activity this way. It illuminates our understanding of the evolution of federal law, particularly in a domain that is so long presumed to necessitate a unitary federal role. Indeed, with respect to nuclear power, the concept of a strong role for states in developing energy policy seems completely at odds with the traditional account of nuclear licensing. Nevertheless, we are seeing increasing heterogeneity among states in their approaches to nuclear policy in particular, and energy policy more generally. Turning the traditional understanding of regulatory federalism on its head suggests ways forward for electricity markets to better integrate valued attributes. Nevertheless, any evaluation of policies aimed at moving markets toward greener, more reliability electricity sources must acknowledge that electricity market governance is a far more complex, multilayered, and ideologically contentious enterprise than ever before.

B. Policy Options: New Terms for the Regulatory Contract

In many ways, governance challenges provide opportunities for innovation. There are numerous options at the federal, regional, and state levels to try to ensure that reliability and environmental costs are better reflected in electricity prices. Some of these interventions attempt to alter the structure of the markets themselves in ways that will encourage new parties to the regulatory contract. Others are directed at the terms of existing regulatory contracts, influencing the value of what is traded on existing markets. None is panacea, but our aim is to bring these options together, relate them to our tripartite framework, and ask what insights they promote in the aggregate.

In setting forth these options, we have made the deliberate choice of organizing them according to the level of government at which they would be implemented. This organizational approach is somewhat artificial because some options rely on multi-jurisdictional cooperation, while others could be implemented without regard to jurisdiction. But we believe this organization is preferable to an approach that would use the broad categories of market-based and regulatory options for two reasons. First, the distinction is not so neat; market-based approaches require a regulatory framework. Second, fundamental to policy comparisons are choices of institutional design; we prefer to make the benefits and drawbacks of such choices explicit.

1. Federal Initiatives

Beyond existing tax credits, subsidies, and environmental controls for specific generation sources, what more could the federal government do to better integrate reliability and social costs into electricity markets? As we have seen, the United States is faced with significant mismatches between valuable electricity attributes and the operation of the markets. A large part of this mismatch comes from the failure of federal law to keep up with rapid changes; another contributor is the piecemeal and asymmetric approach to electricity generation fuels.

\[267\] See generally Hogan, supra note 49.
\[268\] See generally BOSELMAN ET AL., supra note 37 (describing different federal regulatory regimes for hydro, coal, natural gas, nuclear, and renewables).
Scholars and policymakers have proposed numerous statutory solutions, but ongoing congressional gridlock implies that we ought to be skeptical about policy initiatives that require legislative action.

We conclude, as others have, that finding room to act within federal agencies’ discretionary authority is a more promising approach. Agencies do experience successes in this regard, notwithstanding the constant political pressures under which they too must operate. FERC, for example, has utilized its remedial authority under the Federal Power Act to bring about significant changes furthering renewables penetration and the opening of the markets. EPA, as well, has effectuated significant change in the regulatory environment under its CAA authority. And beyond these high-profile examples, agencies can make significant policy headway in their more interstitial, day-to-day decisionmaking.

Admittedly, agencies have many masters. The executive, courts, legislative oversight, and stakeholders exert considerable pressure on agencies to implement particular policy objectives. But their ability to pursue such objectives notwithstanding congressional gridlock means that policy options at the federal agency level cannot be ignored. We outline some of the possibilities here, considering both changes to the market itself, and changes to what is sold on the markets.

First, as already noted, FERC has significant authority in its role as designer and regulator of the wholesale markets. It has used its authority to create those markets in the first place, and it has played a role in the greening of the grid by easing access for renewables. Thus, some have argued that FERC has the authority to impose a carbon adder on wholesale sales of electricity—and ought to exercise it. On the other hand, FERC has been reluctant to

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270 See Freeman and Spence, supra note 20, at 82-93 (explaining why gridlock is likely to continue).
271 Joel B. Eisen, Smart Regulation and Federalism for the Smart Grid, 37 HARV. ENVTL. L. REV. 1, 50-54 (2013); supra note Freeman & Spence, supra note 20, at 80-81; Hammond & Markell, supra note 201, at 316.
272 See Hammond, Deference Dilemma, supra note 116, at 1782-85 (describing political climate leading to Yucca Mountain stall).
274 See Freeman & Spence, supra note 16, at 28-42 (describing these initiatives).
275 Hammond & Markell, supra note 201, at 315-16.
276 E.g., Order 888, supra note 4 (mandating open access to grid).
277 Order 1000, supra note 273 (mandating transmission planning and standardized cost allocation). FERC, however, was careful to clarify that its purpose was not to favor renewables; it stated “[b]ecause we are not mandating the consideration of any particular transmission need driven by a Public Policy Requirement, we disagree with [commenters’] that we are favoring renewable energy resources over other types of resources.” Order 1000, 76 Fed. Reg. at 49,877. Nevertheless, most observers seem to agree that the effect of Order 1000 was greater renewables integration. E.g., Christopher J. Bateman & James T.B. Tripp, Toward Greener FERC Regulation of the Power Industry, 38 HARV. ENVTL. L. REV. 275, 307 (2014).
directly impose environmental considerations on the markets, and there is some question whether the scope of its authority extends so far.\footnote{See Grand Council of the Crees (of Quebec) v. FERC, 198 F.3d 950 (D.C. Cir. 2000) (rejecting, on zone-of-interest standing grounds, tribe’s argument that FERC should have considered environmental impacts as part of just-and-reasonable rate inquiry). FERC itself has taken this position. See 18 C.F.R. § 380.4 (categorical exclusion of rate filings from NEPA). FERC does have power to approve rates that take into account state environmental considerations. See Cal. Indep. Sys. Operator Corp., 141 FERC 61,237, at 29 (2012) (permitting tariff revisions to account for California’s carbon cap-and-trade program); Cal. Pub. Util. Comm’n, 133 FERC 61,059 (2010) (permitting state rates to account for full avoided cost including environmental consideration); Jim Rossi & Tim Hutton, Federal Preemption and Clean Energy Floors, 91 N.C.L. REV. 1283, 1310 (2013) (arguing FERC need not treat PURPA’s avoided cost mandate as imposing a ceiling on state incentive rates).} Reading FERC’s authority to ensure rates are “just and reasonable” against the historical understanding of the regulatory contract seems to limit its jurisdiction to matters related to economic interests relating to the consumers and investors.\footnote{See Grand Council of the Crees, 198 F.3d at 956.} But if the regulatory contract is better conceived as a legal and institutional arrangement contextualized by policy goals, perhaps there is room for argument favoring carbon adders.

As our framework in Part I suggests, however, externalities are not the only attribute of electricity that matters. Reliability and flexibility are important both for maintaining reasonable rates and for the technical operation of the grid. Furthermore, FERC’s authority to ensure reliability, at least, is far more easily settled than its ability to directly consider environmental factors. Thus, a reliability and/or flexibility adder might have better traction, both as a jurisdictional and as a political matter.\footnote{See John S. Moot, Subsidies, Climate Change, Electric Markets and the FERC, 35 ENERGY L.J. 345, 372 (2014) (“any remedies should focus, as much as practicable, on protecting the market, not individual competitors”).} Certainly, deciding the price of reliability would be a complex task.\footnote{Cf. Elec. Power Supply Ass’n v. FERC, 753 F.3d 216, 237-39 (D.C. Cir. 2014) (Edwards, J., dissenting) (explaining FERC’s approach to valuing DR).} But the possibility of directly accounting for this attribute—beyond the indirect approach of SCED—should be considered given its importance to the grid.

There is some appeal to approaches that set overarching rules of the game rather than singling out a particular source of generation. But it is clear that broad-based changes will still result in perceived winners and losers. To the extent that such changes make the markets operate more efficiently, we should be indifferent to disparate impacts on particular fuel sources, but politics do not operate in such an idealized world. EPA’s Clean Power Plan, for example, is meant to apply broadly, but it has generated staggering opposition from many different groups that perceive a disadvantage.\footnote{E.g., Murray Energy Corp. v. EPA, No. 14-1151 (D.C. Cir. filed June 2014) (coal company challenge to EPA’s Clean Power Plan).} An alternative (or perhaps complimentary) approach is to reexamine the licensing schemes for power sources that are licensed at the federal level. Here we return to the nuclear example.\footnote{We focus here on nuclear, but note that hydro is also licensed at the federal level. California v. FERC, 495 U.S. 490, 496 (1990).}

First, we note a counter-intuitive ramification of strongly preemptive and expansive federal regulatory schemes: consistent with the emerging federalism literature, such schemes leave room for state innovation on second-order matters.\footnote{See supra note 263 (collecting sources).} In the nuclear context, this means

www.law.berkeley.edu/files/ccelp/FERC_Report_FINAL.pdf. Briefly summarized, the argument is that environmental externalities permit GHG emitters to charge lower prices than they otherwise would, making the markets inconsistent with the just and reasonable mandate and triggering FERC’s remedial power under FPA § 205. See supra at 5.
that states have incorporated innovations in rate structures, licensing, and construction oversight designed to balance the need to provide clean, reliable electricity with the mandate of just and reasonable rates.286 The details of these innovations are presented below; the important point for now is that this experience suggests the potential viability of new federal approaches to nuclear power plant licensing that might decrease the nuclear risk premium while still prioritizing safety.

There is currently significant duplication in federal and state licensing schemes. For example, states often require status reports and updates, including safety information, just as NRC does.287 Inefficient regulation imposes costs, and prospective new entrants are particularly disadvantaged with regard to licensing new plants and innovative reactor designs. Ultimately, perhaps a regulatory scheme of shared authority would be more effective—though this would admittedly require legislative intervention.288 Even if limited authority were not extended to states, overhauling the federal regulatory scheme is an important option—and not one dependent on congressional action. As noted in Part II, NRC made major changes to its licensing scheme in the 1980s as part of its own efforts to reduce the risk premium.289 The new experience gained under the current regulations should be put to work in updating those regulations as necessary.290

Others have noted the need for a different kind of licensing scheme for new nuclear technologies like small modular reactors (SMRs), which cannot hope for economic viability if they must proceed under the traditional licensing scheme.291 NRC itself is studying the problem and should make such changes a priority.292 Relevant to both attracting new entrants and retaining the existing nuclear fleet, NRC’s Near-Term Task Force, which reported on lessons learned from Fukushima, has also recommended revamping NRC’s safety regulations to better marry the defense-in-depth concept to probabilistic risk assessment.293 And of course, the Nuclear Waste Policy Act has stalled perhaps past the point of any return; numerous recommendations for a new approach are on the table, including an NRC rule issued in 2014.294

Notwithstanding NRC’s authority to make regulatory changes, it cannot be overemphasized that doing so would prompt significant backlash from groups opposed to nuclear


287 See infra Part III.B.2.


289 Citizens Awareness Network, Inc. v. NRC, 391 F.3d 338, 343 (1st Cir. 2004) (describing shift from part 50 to part 52 licensing scheme).

290 Moreover, more research is needed to align the insights of behavioral psychology to effective regulatory approaches designed to enhance the efficiency of regulation. Cf. SUNSTEIN, supra note 169.


292 73 Fed. Reg. at 60,613 (describing initial efforts to address safety and licensing issues related to advanced reactors like SMRs); BLUE RIBBON COMM’N, supra note 269, at vii (listing recommendations).

293 NTTF Report, supra note 177, at 15-25.

294 Final Rule, Continued Storage of Spent Nuclear Fuel, 79 Fed. Reg. 56,238 (Sept. 19, 2014) (finding reasonable assurances of safety of long-term spent fuel storage);
power. As explained in Part II, risk theory may hold explanatory force for the desire to regulate nuclear power as strictly as possible.\textsuperscript{295} The courts’ response to such initiatives, moreover, may be difficult to predict.\textsuperscript{296} Congress and the President would likely get involved, though specific outcomes may depend on political parties. The inevitability of such hurdles, however, is a feature of the landscape for any NRC initiatives. Thus, we discount their impact somewhat. Public choice theory, after all, also predicts that NRC might have an interest in reducing the nuclear risk premium; the agency stands to lose importance over time if the number of nuclear reactors dwindles.\textsuperscript{297}

2. \textit{State Initiatives}

Where traditional rate regulation and vertically integrated utilities continue to predominate (mainly the southeastern United States), states can exert more direct and effective control over market prices and investment decisions. For example, some states provide a gatekeeping function to market entry through the process of IRP.\textsuperscript{298} IRP, which sometimes attempts to incorporate projected environmental impacts into electric generating capacity planning decisions, is conducted in some form in at least twenty-seven states.\textsuperscript{299} State IRP processes pursue this objective in at least two ways: first, by forcing utilities to consider demand-side resources (energy efficiency and conservation) in making decisions about how best to meet projected future electric energy needs; and second, by requiring planners to consider the environmental costs new generating plants will produce.\textsuperscript{300} A minority of states also articulate a goal of maintaining fuel diversity in capacity planning decisions.\textsuperscript{301} In addition to trying to value fuel diversity, several states employ “adders” to the estimated costs of power for new plants representing the cost of externalities generated by those plants over their lifetimes.\textsuperscript{302} States’ methodologies for valuing externalities vary considerably.\textsuperscript{303} The key point, however, is that

\textsuperscript{295} See supra Part II.B.


\textsuperscript{297} But see Allison M. Macfarlane, Chairman, NRC, Remarks to the National Press Club (Nov. 17, 2014) (prepared remarks available at http://www.nrc.gov/reading-rm/doc-collections/commission/speeches/2014/s-14-012.pdf) (“I believe it’s time for the NRC to develop regulations specific to the decommissioning of nuclear power plants, both to help utilities through decommissioning and to structure public expectations of the process.”).


\textsuperscript{301} See supra note 67 and accompanying text.

\textsuperscript{302} See, e.g. Boyd, supra note 20, at 1695-96 (collecting examples); Wilson & Biewald, supra note 300, at 16-25 (same).

\textsuperscript{303} For one example, see MINN. STAT. § 216B.243(3)(a)(1994). The statute requires the Minnesota Public Utilities Commission to “quantify and establish a range of environmental costs associated with each method of electricity generation.” \textit{Id.} § 216B.2422(3)(a); see also \textit{In the Matter of Quantification of Environmental Costs}, 578 N.W.2d 794 (Minn. App. 1998) (upholding PUC regulations); \textit{Re Quantification of Envtl. Costs}, 150 PUB. UTIL. REP. 4th (PUR), at 137 (explaining how environmental externalities are quantified in Minnesota); Jonas J. Monast & Sarah K, Adair, \textit{The Triple Bottom Line for Electric Utility Regulation: Aligning State-Level Energy, Environmental, and Consumer Protection Goals}, 38 COLUM. J. ENVTL. L. 1, 40-41 (2013) (collecting further examples of state PUCs considering environmental factors in exercise of general authority). Valuation is a complex process, but resources
some states incorporate externalities into decisions about which plants to build, if not into decisions about which plants to dispatch to serve load.

Once again, this approach is most easily achieved in states that can guarantee a return on investment. If plants are to operate in the wholesale markets and those markets remain at status quo, a state’s choice of generation mix may not be most optimal where only cost is directly valued directly. In other words, if a state favors generation sources that produce fewer externalities but that have higher marginal costs, those sources will not fare as well in the market. This may help explain why new nuclear reactor construction is currently taking place only in traditionally regulated states. A look at those states’ approaches illustrates additional policy options at the state level. It also suggests that regulated states may have more flexibility than restructured states to influence how cost, reliability, and lack of externalities are optimized.

One policy initiative at the state level is to authorize utilities to collect from customers the carrying costs of major projects during the lengthy construction phase. The Georgia Nuclear Financing Act, enacted just after Southern Company sought authorization from Georgia’s PUC to construct the Vogtle units, permits Southern Company to collect from ratepayers the financing costs of Vogtle during its construction.\(^{304}\) A South Carolina statute, by contrast, permits recovery of carrying costs for utilities seeking to construct base load plants, which are defined as new coal or nuclear generation with generating capacity of 350 megawatts or greater.\(^{305}\) As yet another example, Florida’s PUC has issued a rule permitting recovery of carrying costs for new nuclear construction.\(^{306}\) These initiatives are not without controversy; sustained opposition illustrates that even with state support, the nuclear risk premium remains.\(^{307}\)

In regions where competitive wholesale markets exist, states have sought creative ways to compensate existing nuclear generation for its reliability and environmental value, notwithstanding the market’s failure to do so. For example, a study by the New York Independent System Operator (NYISO) concluded that if the aging R.E. Ginna nuclear power plant in New York were to retire, its loss would result in numerous bulk-transmission system and non-bulk local distribution system reliability violations.\(^{308}\) As a result, New York’s Public Service Commission approved Exelon’s request to seek a reliability support services agreement
with a transmission owner in order to keep the plant operating despite its loss of a long-term power contract and inability to operate in the low-priced power market. According to some estimates, the new power contract would charge over eighty percent more than wholesale rates. But the Commission reasoned that the power source’s reliability and carbon-free capability made it a key asset in the state’s generation fleet.

Other state activities echo the notion that reliability as an attribute is undervalued. Ohio’s PUC, for example, is considering whether to permit a rate rider in its retail rates to make up for low wholesale rates in order to retain existing nuclear capacity. Consider also the Illinois House of Representatives’ recent resolution calling on various state agencies to prepare reports “showing how the premature closure of existing nuclear power plants in Illinois will affect” reliability and capacity for the Midwest region, increased GHG emissions, and the state’s economy. The resolution instructed agencies to include findings about potential market-based solutions to avoid premature closings of the state’s nuclear power plants. Among the resolution’s findings were the importance of nuclear power to meeting EPA’s Clean Power Plan proposal, ensuring reliability and capacity, and preserving numerous nuclear-power related jobs in the state.

The report, issued January 25, 2015, considered several market-based solutions: relying purely on the existing market; a cap-and-trade program; a carbon tax; a low-carbon portfolio standard; and a sustainable power planning standard. For all of the options, however, it recommended further research, cautioning that any approach directed at nuclear power plants “should be mindful of the looming Clean Power Plan compliance requirements.” So far, the low-carbon portfolio standard appears to have the most traction. In fact, this possibility relates to another important state initiative already noted in Part I: RPSs. RPSs have grown steadily in numbers and strength since the early 1980s, and today two-thirds of the states have in place some form of RPS. RPSs vary considerably in their design, but they typically specify some percentage of electricity sales within a state that must or should be attributable to renewable fuel sources. Developments in federal law—particularly, the proposed Clean Power Plan—as well

311 Id.; see also NEI, ECONOMIC IMPACTS OF THE R.E. GINNA NUCLEAR POWER PLANT 2 (Feb. 2015) (concluding plant is “significant economic contributor to the region and New York”).
312 But see PPL Energyplus, LLC v. Solomon, 766 F.3d 241 (3d Cir. 2014) (holding Ney Jersey’s Long Term Capacity Pilot Program Act preempted by Federal Power Act because it regulated wholesale capacity prices; statute was aimed at attracting new natural gas generation); PPL Energyplus v. Nazarian, 753 F.3d 467 (4th Cir. 2014) (similar).
314 Id. at 1-4. In addition, the resolution also called on FERC and RTOs to adopt rules and policies to help ensure the continued operation of nuclear power plants. Id. at 6.
318 For an up-to-date list, see DATABASE OF STATE INCENTIVES FOR RENEWABLES & EFFICIENCY, www.dsireusa.org (last visited Mar. 5, 2015).
319 Id.
as a growing appreciation for other low-carbon resources, have pushed some states to revise their RPSs to emphasize carbon neutrality rather than renewable fuels per se. Ohio, for example, has a low-carbon standard, which mandates that by 2025, half the mandated 25% must come from renewables, while the other half must come from sources like third-generation nuclear power, energy efficiency, and clean coal technology.\textsuperscript{320} As described in Part I, RPSs function as indirect influences on cost, permitting sources meeting the standards to bid lower willing-to-accept prices into the wholesale markets.

In considering state options, one question is whether regulated states have any advantage over restructured states. Certainly the ability to guarantee rate recovery for construction carrying costs, as exemplified by Georgia’s example, is far clearer in states that utilize traditional notions of the state regulatory contract, including cost recovery. Note, however, that this traditional approach to incentivizing investment is not unique to nuclear power, or to traditionally regulated state markets. Remember that even in competitive markets, the rates of transmission and distribution (“wires”) companies remain regulated. So wires companies can recover their investments in smart meters and grid storage, for example, which are also aimed at enhancing grid reliability.\textsuperscript{321}

But recent experience also suggests that restructured and regulated states face different regulatory landscapes that impact the menu of available options. Consider the following. In the early 2000s, two states in the eastern portion of PJM, New Jersey and Maryland, grew dissatisfied with wholesale electricity prices in eastern PJM. Policymakers in both states concluded that the PJM capacity market was not inducing sufficient investment in new generation facilities in eastern PJM, and undertook to subsidize construction of new natural-gas fired generation within their state borders. Reasoning that these subsidies would distort prices in the PJM market, in 2014 two different federal circuit courts overturned each of these two subsidy programs as preempted by the FPA, which grants the FERC exclusive authority to regulate wholesale rates.\textsuperscript{322} A key part of both courts’ rationale was that by restructuring, the states had thrown “their lot with the federal interstate markets” and relinquished their former regulatory autonomy.\textsuperscript{323} Thus, even though the states still retained authority over siting and construction, by giving up their authority to set electricity rates under the traditional approach, they had also limited their ability to compensate for distortions that generators within their borders might encounter.\textsuperscript{324}

3. Regional Initiatives


\textsuperscript{321} Recovery remains subject to PUCs’ decisionmaking and state law. See Eisen, supra note 271, at 17-20 (describing obstacles); see also Inara Scott, \textit{Teaching an Old Dog New Tricks: Adapting Public Utility Commissions to Meet Twenty-First Century Climate Challenges}, 38 HARV. ENVT. L. REV. 371 (2014) (noting challenges and solutions).


\textsuperscript{323} Nazarian, 745 F.3d at 473; see also Solomon, 766 F.3d at 748 (“New Jersey divorced the entities that generate electricity from those that supply it.”).

\textsuperscript{324} E.g., 766 F.3d at 248.
Much like the federal initiatives, regional attempts to push electricity markets to better value environmental and reliability concerns are largely disaggregated. Environmental considerations have emerged as a result of state cooperation, influencing the cost of what is traded on the wholesale markets. A notable example is the Regional Greenhouse Gas Initiative (RGGI), which is a voluntary carbon trading regime created by a group of northeastern states.\(^{325}\)

There are few other examples, suggesting the potential to do more but also reinforcing the governance issues described above. Notably, the Clean Power Plan envisions state cooperation to achieve GHG emission-reduction goals, suggesting at the very least federal support of region-driven approaches.

Reliability, by contrast, has generally been the concern of multiple layers of governmental and private sector actors, including FERC, the North American Electric Reliability Corporation (NERC),\(^{326}\) regional reliability entities overseen by NERC,\(^{327}\) RTOs/ISOs, and states. Every NERC region has an established reserve margin target, or desired amount of available generation over and above anticipated peak demand. In NERC regions dominated by traditionally regulated, vertically integrated electric utilities, meeting the reserve margin target is a simple matter because utilities have an incentive to invest in generation.\(^{328}\) In areas with wholesale markets overseen by RSOs/ISOs, capacity markets, mentioned in Part I, represent another way to try to meet reserve margin targets.

To date, capacity markets have not attempted to place a value on fuel diversity or social costs.\(^{329}\) Indeed, it is the failure of competitive wholesale markets to reward the combination of reliability and low emissions that has led states like Illinois, New York, and Ohio to consider incentives to keep plants open, as described in the previous section. Capacity markets could explicitly incorporate fuel diversity into their selection criteria to avoid these problems. On the other hand, regional capacity planning presents collective action problems, which in turn can present federalism problems, as the examples of New Jersey and Maryland above reveal. Given the conflicts between states in the eastern and western portions of PJM, moreover,\(^{330}\) it is not difficult to imagine that disputes will erupt within regional entities over attempts to value fuel diversity or social costs in capacity markets.

The Texas grid operator has eschewed capacity markets in favor of letting wholesale prices rise to cap of $9,000/MWh (as compared with average prices of less than $50/MWh) as a way of rewarding investment in new capacity.\(^{331}\) However, concerned that high prices alone might not be a sufficient incentive, Texas regulators have explored intervening in ancillary


\(^{327}\) The boundaries of these regional entities correspond roughly to the boundaries of RTOs/ISOs in organized power markets. See **NERC, REGIONAL ENTITIES**, http://www.nerc.com/AboutNERC/keyplayers/Pages/Regional-Entities.aspx (last visited Mar. 6, 2015) (showing boundaries).

\(^{328}\) This effect is attributed to the cost-of-service approach to ratemaking. See sources cited supra note 143.

\(^{329}\) See NEI, **News: Exelon on the 2014 PJM Capacity Market Auction**, June 12, 2014, http://www.nei.org/News-Media/News/News-Archives/Exelon-on-the-2014-PJM-Capacity-Market-Auction (criticizing PJM capacity planning process because it “reveals that the market does not sufficiently recognize the significant value that nuclear plants provide in terms of reliability and environmental benefits.”).

\(^{330}\) Supra text accompanying note 260.

\(^{331}\) **ERCOT, SYSTEM-WIDE OFFER CAP AND SCARCITY PRICING MECHANISM METHODOLOGY 5** (Apr. 2013) (on file with authors).
services markets to increase payments to providers of ancillary services (essentially, a reliability adder), which are very short-term reserves. 332 Traditionally, the grid operator dispatches reserves the same way it dispatches other generation resources, using the SCED rule.

In any of the wholesale markets, one could conceivably interject social costs into the dispatch system as well, through the use of adders in the dispatch process. The idea behind social cost dispatch is to modify current SCED rules by adding to each source’s bid cost an estimate of that facility’s marginal social costs (that is, estimated marginal value of its external costs). This is conceptually straightforward, but extremely complex in practice. In theory, such adders would be equivalent to the imposition of optimal emissions tax, 333 imposed only on electric generators. The adder would, like the tax, force firms to internalize an optimal amount of external costs.

There are scholars who have proposed methods of full social cost (or “environmental/economic”) dispatch, 334 but others believe it is unworkable. 335 EPA’s recently-proposed Clean Power Plan aims to reduce greenhouse gas emissions from the electricity sector by encouraging (but not requiring) states to dispatch cleaner sources of power—nuclear, natural gas, and renewables in place of coal, 336 thereby introducing environmental considerations into dispatch decisions directly. 337 But that plan has met with hostility from Republican appointees to FERC, precisely because it would represent a step toward an “environmental dispatch” model. 338 Thus, even if such costs could be calculated appropriately, the political viability of such an approach is questionable.

333 Theoretically, the tax should be set a price that will induce generators to reduce pollution to the point at which the marginal benefit of the next unit of pollution equals its marginal cost. THOMAS TIETENBERG ENVIRONMENTAL AND NATURAL RESOURCE ECONOMICS 52-54 (1992).
335 Perhaps the most prominent scholar opposing full social cost dispatch is William Hogan. See William W. Hogan, Electricity Market Design: Environmental Dispatch, HARV. ELEC. POL’Y GRP. WORKING PAPER (Dec. 4, 2014).
336 Clean Power Plan, supra note 10, at 34,856. The Plan would establish emissions budgets for each state based, in part, on assumptions about how much each state can dispatch cleaner technologies in place of coal-fired power.
337 This has provoked complaints from opponents of the proposed plan who argue that a system of “environmental dispatch” violates the just and reasonable rate requirement. See generally Hogan, supra note 335.
IV. Conclusion

If the foregoing discussion makes daunting the prospect of fully realizing the vision of an efficient, reliable, and green grid, it also suggests reasons for optimism. Numerous actors at every governance level have made efforts towards this vision, and there is room for far more experimentation. This observation, however, returns us to our starting point: what do all of these developments mean for the regulatory contract? We contend that part of the answer lies in the increasing heterogeneity observable across and among governance levels. The regulatory contract has long passed the point of being defined by two parties and a nineteenth-century purpose.

Instead, the regulatory contract is better conceived as a network, loosely bound by the contours of markets as well as the initiatives of multiple layers of government and private actors. But more work is needed to fully align this concept within the dual-visioned, clean and efficient grid. As we have shown, a number of mismatches between old regulatory regimes and dynamic markets have resulted in a failure to value some attributes of electricity. The experience of nuclear power demonstrates some of these mismatches. Prospective new entrants are disincentivized to construct high-capital projects with an added risk premium; current players are being priced out of the markets, notwithstanding their reliable, clean contribution to the grid.

It is of great interest, then, that the prospect for new nuclear power seems best in states that embrace more traditional notions of the regulatory contract. On the other hand, those states have been innovative, using the regulatory contract as a tool rather than a static construct. And the reactors under construction today were incentivized as well by federal initiatives designed to overcome at least some of the nuclear risk premium. Note as well that restructured states are also considering innovative ways to maintain the reliability and environmental benefits of their existing fleets. These developments are of special significance considering that they have taken place in a field—atomic energy law—long perceived as requiring a unified, preemptive federal presence. Overall, this context points to the need for further research that considers various policy options in tandem, rather than in isolation. If the regulatory contract is a network, its component parts must be so analyzed.

This analysis illustrates that the legal framework within which the markets operate shapes those markets. The move from comprehensive regulation and administrative price-setting to competition and market prices does not obviate the need for regulation. To the contrary, regulatory institutions matter because competitive markets sometimes fail to supply valued products and services, just as modern electricity markets under-supply valued attributes of electricity generation by focusing on minimizing costs. If we are to truly pursue a low-cost, reliable, and green grid, we must view the regulatory contract as a flexible mechanism—one that can incorporate a variety of policy options, at multiple governance levels, to change the inputs to the markets or even alter the markets themselves.