CLE READING MATERIALS

Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms

FOR

10:15 a.m. – 11:35 a.m. **ADVANCING ENERGY POLICY**

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- **Cheryl LaFleur**, Commissioner, Federal Energy Regulatory Commission
- **Andrew G. Place**, Vice Chairman, Pennsylvania Public Utility Commission
- Moderator: **Burcin Unel**, Energy Policy Director, Institute for Policy Integrity

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ELECTRICITY POLICY INSIGHTS

Capacity Markets and Externalities

Avoiding Unnecessary and Problematic Reforms

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Sylwia Bialek, Ph.D.
Burcin Unel, Ph.D.

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street
New York, New York 10012

Sylwia Bialek is an Economic Fellow at the Institute for Policy Integrity at NYU School of Law. Burcin Unel is the Energy Policy Director at the Institute for Policy Integrity.

Executive Summary

Many states have recently ramped up efforts to address climate change and accelerate their transition toward cleaner energy sources. To achieve these goals, several states have adopted Renewable Energy Credits and Zero-Emission Credits. These policies pay generators for desirable attributes such as avoiding air pollution externalities associated with electricity generation from fossil-fuel-fired resources. These "externality payments" help level the playing field between emitting and non-emitting generators.

As these policies become increasingly prevalent, policymakers have begun debating whether the payments could negatively affect the efficiency of wholesale electricity markets. In particular, the debate has focused on whether these policies could reduce capacity prices to levels that no longer support economically efficient entry and exit of generators, and threaten resource adequacy. Consequently, various groups have proposed capacity market reforms, with the aim of shielding these markets from the potential price impact of externality payments. In March 2018, the Federal Energy Regulatory Commission approved ISO-New England's Competitive Auctions with the Sponsored Policy Resources proposal. And, in April 2018, PJM Interconnection filed two different proposals to reform its capacity markets with the Federal Energy Regulatory Commission.

But, as we discuss in this report, the premises underlying these reforms are faulty. First, the argument for redesigning capacity markets in reaction to externality payments relies on the argument that resources that get externality payments cannot be considered "economic," as they cannot be supported by only the revenue they earn in wholesale markets. But this argument focuses only on private generation costs, disregarding the market failures associated with the external costs of air pollution from fossil-fuel-fired resources. Externality payments help correct this market failure, and, therefore, they are expected to increase social welfare, improving the efficiency of entry and exit behavior of generators. The reforms will sustain the existing market inefficiencies.

Second, the justification for proposed reforms tends to overlook the role of inherent market forces. Capacity market prices, by design, adjust based on supply and demand. The proposed reforms largely disregard those adjustments, thereby failing to reach their self-proclaimed goal of restoring prices that would have resulted in the absence of externality payments. In addition, capacity market designs have their own flaws that might contribute to inefficiency, but those are unrelated to externality payments. Hence, there is no conclusive evidence that capacity markets are under threat or that any decrease in capacity market prices due to externality payments would be economically inefficient.

Rushed market design changes based on the unsupported assumption that state policies negatively affect capacity markets may actually harm the functioning of the markets, while potentially undoing states' efforts to combat pollution and climate change.

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Introduction

As states around the country ramp up efforts to address climate change and transition toward cleaner energy sources, many have relied on policy tools such as Renewable Energy Certificates (RECs) and Zero-Emission Credits (ZECs). These programs offer payments to resources for the value of generating energy that is associated with desirable attributes such as avoided carbon-dioxide emissions (externality payments). As a result of the increasing prevalence of such policies, policymakers have begun debating their potential effect on wholesale electricity markets.

Some commentators have argued that externality payments could distort capacity markets.[1] They maintain that these payments allow generators to bid into the capacity market at below the generators' costs of providing capacity, and allow generators that have received those payments to reduce the market-clearing price for capacity. By causing a reduction in capacity prices, they argue, the externality payments would send incorrect signals for the entry and exit of generators.[2] The argument maintains that those distortions would in turn lead to economically inefficient outcomes, resulting in elevated total costs of the system and potentially flawed functioning of the market by failing to ensure that enough capacity is present to meet demand at all times, threatening resource adequacy. Given such concerns, state and federal regulators, as well as other stakeholders, have started discussing the potential need to "accommodate" or "mitigate" the effect of states' environmental and public health policies (state policies) in the design of wholesale electricity markets.[3]

As a result of the discussions, proposals for capacity market reforms that would counteract the impact of the externality payments have emerged. For example, PJM Interconnection (PJM)—a Regional Transmission Organization (RTO) that coordinates the movement of wholesale electricity in all or parts of thirteen states and in the District of Columbia—has proposed two different models to reform capacity markets in order to counteract any potential effect of those externality payments.[4] ISO-New England (ISO-NE)—an independent, non-profit RTO, serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont—also proposed a capacity market reform that was approved by federal regulators in March 2018.[5]

But, as we discuss in this report, the premises underlying these proposals are faulty. For example, there is currently not sufficient evidence that the state policies designed to reduce emissions negatively affect the economic efficiency of capacity markets from a societal welfare perspective. On the contrary, rushed design changes may actually harm the functioning of the markets, while potentially undoing the states' efforts to combat pollution and climate change.

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1 *See generally* Monitoring Analytics, LLC., 2016 State of the Market Report for PJM (2017) [hereinafter "2016 State of the Market Report for PJM"], http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf; Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 4 (2018); for some of the contributions to the discussions, *see* FERC Docket No. AD17-11-000, *State Policies and Wholesale Markets Operations* and FERC Docket No. ER18-619, ISO-*New England Inc.* [hereinafter "FERC Dockets"] (for comments, filings, and transcripts of technical conferences), https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=&View=L

2 *See generally* FERC Dockets, *supra* note 1.

3 *See generally* FERC Technical Conference, *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., Docket No. AD17-11-000*, FERC (May 1-2, 2017), https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=&View=L (follow hyperlinks for "Transcript, May 1" and "Transcript, May 2").

4 PJM Interconnection, L.L.C., ER18-1314-000, Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market (2018) [hereinafter "PJM Filing"].

5 *See* Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205 (2018).

Externality payments are designed to correct market failures resulting from the external costs of pollution and help increase the overall economic efficiency of the market. Changes in capacity markets designed to counteract the effect of externality payments will have ripple effects on the electricity supply, and will negatively affect renewable resources. For example, the changes will likely increase available capacity, which—all else remaining equal—will reduce energy market prices and thus energy market revenue. This decrease in energy market prices would be especially worrisome for renewable and limited-duration resources that rely more heavily on energy market revenues than capacity market revenue, as these resources can be severely limited from participating in capacity markets.[6] Proposals that make it more difficult for non-emitting resources to clear in the regular capacity markets will additionally diminish capacity market revenue for any carbon-free generators that do participate, adding a second blow to their profitability.

Current capacity reform proposals would thus reverse that positive effect of externality payments on social welfare and allow the inefficiencies in wholesale electricity markets to continue—namely, the externalities associated with air pollution.

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[6] *See* Jennifer Chen, *Is Capacity Oversupply Too Much of a Good Thing?*, 34 Nat. Gas & Elec. 15 (2017), https://doi.org/10.1002/gas.22016.

Background: Electricity Markets, Efficiency, and Externalities

In most regions of the United States, electricity is first traded in wholesale markets before being sold and distributed to consumers—households and most of businesses—in retail markets. The wholesale markets are managed by regional oversight entities called RTOs and ISOs, and regulated by Federal Energy Regulatory Commission (FERC). Most wholesale market operators run markets for energy, capacity, and ancillary services.[7] Currently, there are seven ISOs/RTOs operating in the country,[8] with PJM running the nation's largest wholesale electricity market.

Energy markets

As electricity cannot yet be stored in an economically efficient manner in large quantities,[9] generation needs to be perfectly aligned at every instant with energy consumption, which is volatile and tends to vary during the day and between seasons.[10] To address this problem in the energy markets, the wholesale price for a megawatt-hour (MWh) of electricity is established through auctions based on supply offers submitted by generators and demand bids submitted by load-serving entities (LSEs) that serve end users. Hourly day-ahead auctions ensure that energy demand and supply can be balanced at low cost, leading to a significant variation in energy prices during the day. Real-time wholesale auctions further facilitate the alignment between energy supply and demand by correcting for any unforeseen changes in market conditions.

In the auctions, LSEs submit their demand bids based on the predicted electricity consumption of the end users, and generators submit their supply bids based on the cost of generating electricity. Resources that win the auction are said to "clear" the market. The generator with the lowest bid clears the market first, followed by the next cheapest, until demand is met. The wholesale energy price for all generators that clear the market is then determined by the bid of the last resource to clear the market, plus other charges necessary to reflect the operational constraints of the grid, such as congestion and energy losses. Where there are competitive bidders, this design creates an incentive to bid true marginal costs because generators look to submit their lowest possible bid, in order to maximize the chance of their bid being

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[7] The role of energy and capacity markets is explained below. Ancillary services encompass variety of operations beyond generation and transmission that help grid operators maintain a reliable electricity system, among others, maintaining the proper flow and direction of electricity, addressing imbalances between supply and demand, and facilitating the system recovery after a power system event. As the revenues from ancillary markets constitute only a small portion of revenue for generators, this report focuses on energy and capacity markets. *See* David B. Patton et al., 2016 State Of The Market Report For The New York Iso Markets, at 14 fig.1 (2017), http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf (for the typical distribution of revenue for generators).

[8] The seven ISO/RTOs are: California independent system operator (CAISO), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator, Inc. (MISO), ISO New England (ISO-NE), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP).

[9] Recent progress in energy storage technologies is likely to decrease the need for instantaneous coordination of electricity generation and consumption. For an overview of the currently available technologies and their costs see Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Energy Storage and Greenhouse Gas Emissions* (forthcoming), http://policyintegrity.org/files/publications/ReveszUnel_EnergyStorage.pdf.

[10] Demand for electricity is low during the night. It starts to increase in the morning, and remains high through the day. It usually peaks in early evening when it is mostly used in individual households returning from work. The substantial seasonal differences in energy usage, on the other hand, are mostly due to the varying need for heating and air conditioning.

cleared, while at the same time recovering their marginal cost of generation.[11] By encouraging generators to bid their marginal costs, this auction design ensures that the private variable costs of producing the total electricity demanded at a given time and location is minimized.

Capacity markets

In some regions, such as the Northeast and Midwest, energy markets are complemented by capacity markets, in which generators can receive additional payments for committing to provide generation capacity at a certain time period. Capacity is measured in megawatts (MW) and reflects the generator's potential to reliably generate electricity during a certain period.

The existence of capacity markets sets electricity generation apart from most other sectors, where firms are rewarded only for their actual production and not for their ability to produce. Proponents of capacity markets argue that they are needed due to the unique features of electricity as a commodity, and some particularities of electricity market design that make it vulnerable to market failures.

First, electricity demand is considered to be price inelastic. In other words, end-users do not significantly alter their electricity demand as the wholesale prices change. One of the main reasons for this lack of response to price is that end users rarely observe wholesale electricity prices directly, as LSEs usually charge consumers flat rates as set by state regulators in rate cases. Therefore, even when wholesale market prices substantially increase, signaling the scarcity of energy generation, consumers do not receive this price signal and hence they do not adjust their energy usage. Consumers may thus demand more electricity than is feasible to generate at a given time, which can lead to blackouts.

Second, electricity markets are often haunted by a "missing money problem."[12] The problem refers to the idea that energy prices in competitive wholesale electricity markets do not adequately reflect the value of investment in generation needed to create a reliable electric supply.[13] Because electricity cannot be stored at a large scale, and electricity demand fluctuates significantly during the day and the year, sufficient capacity must be built to balance supply and demand reliably under any foreseeable demand conditions, in particular under maximum peak demand conditions (called "super-peak" demand).[14] However, super-peak demand, by definition, occurs during only a small number of hours per year (e.g., 10 hours per year).[15] It is only during those super-peak hours that the capacity is almost fully utilized. The fact that enough generation capacity must exist to meet the high demand during these times means that much of the generation capacity sits idle during the rest of the year. To be profitable enough to stay in the market, these generators must earn enough money on energy sales in the super-peak hours when they manage to clear the auction to cover both operations and maintenance costs, as well as their construction costs.[16]

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[11] Every unit that clears the auction receives the same price for a MWh of energy they supply at a given location. Submitting a bid higher than the marginal cost would imply that, if the energy price is higher than the marginal cost but lower than the bid, the generator misses the profits that it would otherwise make. On the other hand, if the generator bids below it marginal cost, it risks clearing an auction where the MWh price will not cover his variable costs of energy supply. Consequently, only those resources that can produce and deliver electricity below the market clearing price—the marginal cost—are dispatched.

[12] Michael Hogan, *Follow the Missing Money: Ensuring Reliability at Least Cost to Consumers in the Transition to a Low-Carbon Power System*, 30 Electr. J. 55 (2017).

[13] *See id.*

[14] The level of peak demand fluctuates around the year in a relatively predictable manner but sometimes may increase to unusually high values, mostly due to extreme weather conditions. *See* Paul L. Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design*, 16 Util. Policy 159, 159–170 (2008).

[15] *See id.* at 160.

[16] *See id.* at 160.

While in theory it is possible for all generators, including the highest-cost generators, to recover their full costs in such a short time interval, in practice there are a number of reasons why this may not happen. Notably, there are price caps in wholesale electricity markets.[17] While such price caps may be justified because they help limit potential market-power concerns and protect consumers, they nonetheless create a distortion: electricity market prices do not accurately reflect demand for reliability during peak-demand hours, and thus might render it impossible for some generators necessary for meeting the peak demand, specifically peaker plants, to recover their investment costs.[18] Consequently, an energy-only market with price caps may induce too little new investment to meet the maximum energy demand during super-peak hours.

Third, system reliability is a public good and markets generally underprovide public goods.[19] During a blackout, no generator is able to sell energy. As a result, when a resource prevents a blackout, benefits accrue to all of the generators that would have been otherwise unable to sell power. Similarly, given that during a blackout no consumer can receive energy, consumers would benefit from a decrease in consumption of any consumer that can forestall any blackout. As with all public goods, electricity's reliability is likely to be undersupplied without intervention in the market.[20]

In light of these limitations, some regions have chosen to set up capacity markets to assure that sufficient capacity is built to satisfy demand and thus ensure reliability at any moment of the year.[21] ISOs/RTOs such as PJM and ISO-NE run these markets by using auctions. Generators submit their bids for making their capacity available whenever the energy market price reaches a certain threshold, usually defined by the electricity price cap.[22] Capacity auctions choose the generators with the lowest offers to meet the necessary level of capacity to ensure resource adequacy—capacity amounts that are close to the predicted maximum demand plus a reference reserve margin.[23] All of the cleared generators receive the same per-MW price, equal to the bid of the last-clearing generator.

These capacity payments supplement earnings in the energy market. As the payments reward capacity only in the amount related to maximum electricity demand, they create incentives for entry up to the point where additional capacity is no

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[17] For example, the electricity markets run by PJM and NYISO caps the admissible offers at $2,000/MWh. However, to comply with FERC Order 831, PJM verifies bids above $1,000/MWh to ensure that they "reasonably [reflect] the associated resource's actual or expected costs prior to using that offer" before using them for calculation of the clearing price. *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, FERC Stats. & Regs. ¶ 31,387 (2016) (cross-referenced at 157 FERC ¶ 61,115), order on reh'g and clarification, Order No. 831-A, 82 Fed. Reg. 53403 (Nov, 16, 2017), FERC Stats. & Regs. ¶ 31,394 (2017), https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf.

[18] Joskow, *supra* note 14, at 162.

[19] System reliability meets the conditions of a public good: it is both non-excludable and non-rivalrous from the perspective of generators and energy end-users. Non-excludability means that it is not possible to prevent individuals from enjoying the benefits of system reliability even if they do not pay for the reliability. Non-rivalry means that system reliability being enjoyed by some of the consumers and generators does not prevent others from enjoying it simultaneously. The technology, however, is eroding the non-excludability feature. *See* Hogan, *supra* note 12; *see* Malcolm Abbott, *Is the Security of Electricity Supply a Public Good?*, 14 Electr. J. 31 (2001) (for background on 'public goods').

[20] *See* Joskow, *supra* note 14, at 165.

[21] For example, PJM, NYISO and ISO-NE run mandatory capacity markets, at MISO the participation in the market is voluntary.

[22] This threshold is usually reached during the super-peak demand hours but could also be a result of some technical problems of some generators, weather conditions disrupting the transportation of energy from some generators, or a mixture of the factors. In such situations the electricity generation becomes scarce relative to the demand, and imbalance between power generation and power consumption may lead to a blackout.

[23] Demand in the capacity market is determined by an administratively defined downward sloping demand curve. This curve is designed to ensure adequate resources to meet expected operating needs. It is therefore is based on the super-peak demand adjusted by reference margins. Reference margins are published periodically by North American Reliability Corporation for individual regions. They dictate how much capacity needs to be obtained in excess of the predicted maximum capacity to serve as insurance against breakdowns in part of the system or sudden increases in energy demand (expressed in percentage terms, usually a value between 10 and 20%). *See M-1 Reserve Margins*, N. Am. Elec. Reliability Corp., http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx (last visited March 29, 2018).

longer needed. In this way, capacity markets ensure there is enough energy generation when it is most needed, thus meeting their basic purpose: ensuring resource adequacy. At the same time, if the total revenue an existing generator can earn is too low for the generator to be profitable, the market will give an exit signal to that generator.

Outcomes of energy and capacity markets are strongly interwoven. Generators have an incentive to bid their true net costs of staying in the capacity market because otherwise they could risk not clearing in the auction. For existing power plants, this incentive leads to them to bid the present value of their current and future costs, adjusted by expectations regarding all future profits from energy and capacity markets (known as the "net going forward cost"). The optimal bid of new entrants corresponds to the costs of building the plants, adjusted by all the expected future profits from energy and capacity markets.[24] Therefore, the resources that manage to make profits on the energy market and thereby (partly) cover their annualized fixed costs are willing to accept lower capacity payments. Holding all other things equal, higher prices on the energy market lead to lower bids in the capacity market. On the other hand, capacity markets affect the long–term composition of resources present in the market, and thus energy prices. The two markets therefore simultaneously affect each other.

Market failures and corrective subsidies

A key principle of economics is that competitive markets ordinarily maximize social welfare. And, any interference with the operation of a free market, if it changes the equilibrium price and quantity, reduces welfare. However, the assumption that competitive markets are economically efficient relies on idealized assumptions about the structure of the market.[25] Market failures often interfere with that ideal vision. For example, market outcomes are not efficient when market transactions fail to take into account the cost of damage they cause to third parties through a "negative externality."[26] Air pollution is a classic example of a negative externality. As a by-product of electric generation, fossil-fuel-fired power plants emit many pollutants such as nitrous oxides, sulfur dioxide, particulate matter, and ammonia.[27] The electricity sector is also one of the main sources of greenhouse gas emissions—29% of U.S. emissions in 2015.[28] All of these emissions harm society,[29] and wholesale electricity markets have been failing to take those external costs fully into account.[30] If polluters do not need to pay for the damages they cause, they will engage in market transactions that result in more pollution than is economically efficient.

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[24] *See* James F. Wilson, *Forward Capacity Market CONEfusion*, 23 Electr. J. 25 (2010) (for the discussion on optimal bids).

[25] For the set of conditions required for competitive equilibria to exist and be efficient see Antonio Villar, General Equilibrium with Increasing Returns 6 (1996) and Robert S. Pindyck & Daniel L. Rubinfeld, Microeconomics 315, 612-13 (7th ed. 2009). *See also* Bethany Davis Noll & Burcin Unel, *Markets, Externalities, and the Federal Power Act: The Federal Energy Regulatory Commission's Authority to Price Carbon Dioxide Emissions*, N.Y.U. Envtl. Law Rev. (forthcoming).

[26] *See generally* Paul Krugman & Robin Wells, Microeconomics 437-438 (2d ed. 2009); Jonathan Gruber, Public Finance and Public Policy 136 (5th ed. 2016).

[27] *See* Jaramillo & Muller, *infra* note 29.

[28] U.S. EPA, EPA 430-P-17-001, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015 (2017), https://www.epa.gov/sites/production/files/2017-02/documents/2017_complete_report.pdf.

[29] For estimates of monetary damages due to air pollution exposure for $PM_{2.5}$, SO_2, NOx, NH_3, and VOC from electric power generation, oil and gas extraction, coal mining, and oil refineries for selected years see Paulina Jaramillo & Nicholas Z. Muller, *Air Pollution Emissions and Damages from Energy Production in the U.S.: 2002-2011*, 90 Energy Policy 202, 202–211 (2016) [for 2011 the paper estimates that damages associated with the investigated emissions totaled 131 billion dollars (in 2000$)]. *See also* Jeffrey Shrader, Burcin Unel & Avi Zevin, Valuing Pollution Reductions. How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources (2018), http://policyintegrity.org/documents/valuing_pollution_reductions.pdf

[30] RGGI permits which are obligatory for offsetting the CO_2 emissions for generators located in some of the states and are an exception here. However, their price level (currently around $3) is far below the external costs associated with emissions of the relevant greenhouse gases.

Whenever the market fails because of externalities, intervention is not just preferable but necessary to ensure that social welfare can be maximized.[31] The typically prescribed, efficient solution for an externality is a corrective tax, forcing the market participants to directly "internalize the externality"[32]—known as the "first-best" option—by, for example, imposing a "carbon price" in the form of an economy-wide emissions tax or cap-and-trade system based on the external damages caused by emissions.[33] However, taxation may not be feasible due to political considerations. As an alternative, policymakers can address negative externalities by subsidizing resources that do not produce the externality.[34] While such policies are generally inferior to taxing the externality directly, they can still substantially improve the economic efficiency of the market. These are known as "second-best" options.

Therefore, corrective subsidies, such as externality payments, that aim at increasing market efficiency in the presence of externalities are an important and desirable tool for policymakers. Corrective subsidies are clearly distinguishable from "traditional" rent-seeking subsidies that result from companies manipulating the social or political environment to increase their profits based on the personal preferences of decisionmakers for certain products, services, or technologies. These traditional subsidies that do not target any market failure reduce social welfare by distorting market allocations, as opposed to increasing social welfare by eliminating externalities.

The combined capacity, electricity and ancillary services markets have been mostly successful at providing reliable energy to consumers.[35] Nonetheless, because these markets have been disregarding a significant externality—pollution—they have failed to ensure that the energy mix is socially efficient.

The existence of externalities changes what can be considered economically efficient. A generating unit that appears to be profitable given its market revenue, and therefore economic when considering only its private costs, may actually be socially uneconomic when its emissions are taken into account because its net revenues are lower than the harm it causes.[36] Similarly, a generating unit that appears uneconomic based on its wholesale market revenues alone may nevertheless be socially economic and viable if it could capture the economic value of its environmental attributes through externality payments. Without incentives for the generators to consider the external costs of their actions, the equal treatment of emitting and non-emitting resources in wholesale markets causes too much electricity to be produced by emitting generators. As a result, energy markets currently do not yield economically efficient outcomes.

A carbon pricing policy, as explained above, would be the first-best economic approach to counteract the greenhouse gas emissions externality. This economically preferred policy takes into account the pollution intensity of the generators,

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[31] Elena Cima, *Caught Between WTO Rules and Climate Change: The Economic Rationale of "Green" Subsidies*, 4 Environ. Law Econ. 379 (2017).

[32] *See id.*

[33] While this report discusses only the externalities related to greenhouse gas emissions, the same principles applies to other pollutants such as nitrous oxides, sulfur dioxide, particulate matter as well.

[34] Gruber, *supra* note 26, at 138.

[35] In 2015, municipal utility customers experienced on average one outage and about two hours of interrupted service, investor-owned utilities' customers averaged slightly more than three hours without electric service, while co-op customers averaged nearly five hours without power over two outage events. David Darling & Sara Hoff, *Annual Electric Power Industry Report* (EIA-861), U.S. Energy Info. Admin. (Sept. 16, 2016), https://www.eia.gov/todayinenergy/detail.php?id=27892.

[36] The phrase "uneconomic" generators has been used in the discussions around the capacity market reforms. While not explicitly explained, it relates to being able to successfully compete in the market and clear the market auctions based on their private costs. *See* Order on Paper Hearing and Order on Rehearing, *ISO New England Inc.*, 135 FERC ¶ 61,029, P 170 (2011) ("Our concern, however, is where pursuit of [states'] policy interests allows uneconomic entry of OOM capacity into the capacity market that is subject to our jurisdiction, with the effect of suppressing capacity prices in those markets.").

sending differentiated price signals to all market participants. This policy would not affect the marginal cost of non-polluting resources, would cause a small increase in the marginal costs of relatively clean sources, and would lead to a large increase in the marginal costs of highly carbon-intensive generators. In other words, the more emissions a resource produces, the more it needs to pay, which reduces its profits. This inevitably leads to a change in the composition of generation capacity, with a fraction of the most emissions-intensive resources pushed to exit the market. At the same time, it would induce entry from cleaner resources.

Importantly, the generation mix reached when emissions taxes or cap-and-trade programs that fully internalize the externalities are implemented is socially efficient because such programs minimize the sum of generators' costs necessary to meet demand given the existing fleet of generators and the external cost associated with this level of electricity production. These policy tools also ensure that the generators face economically efficient incentives for exit and entry, which necessarily reflect the cost of the emissions.

Yet, despite imposing external costs, fossil-fuel-fired resources have been receiving the exact same compensation in wholesale markets for supplying electricity as non-emitting resources. As country-level initiatives to correct that problem have been absent so far, many states have taken the lead in tackling the electricity-related externalities. However, the first-best solutions—an economy-wide emission tax or cap-and-trade program—are often not feasible for states. Consequently, states face the difficult task of choosing the economic instruments necessary to address externalities within the policy tools available to them. Some states have opted to introduce payments for the carbon-free electricity generation by requiring utility companies to buy RECs or ZECs from renewable or zero-emission resources for a certain percentage of their load. By introducing payments that are related to the value of avoided emissions, these policies are an attempt to ensure that the difference in revenues between clean and polluting generators account for the external costs.

Externality Payments Have Not Led to a Need for Capacity Market Reforms

Several ISOs/RTOs are in the process of changing their capacity markets in reaction to state policies that include externality payments. For example, PJM, the nation's largest RTO, recently submitted two proposals to FERC,[37] and ISO-NE recently received approval for a reform.[38] Both PJM and ISO-NE aim to reduce any potential impact that externality payments might have on capacity markets by increasing the market clearing price in these markets.

The proposed changes are all based on the premise that state externality payments allow generators that would otherwise not be profitable, or what ISOs/RTOs call "uneconomic," to enter the market with below-cost bids, causing the "more efficient, lower cost generators" to exit and "more expensive, less efficient generators" to stay "which will ultimately lead to higher costs for consumers."[39] Under this theory, any prices that are affected by externality payments are not competitive, but rather below competitive levels.[40] And, the theory maintains that such prices would distort entry and exit decisions by allowing uneconomic resources to enter or stay, and economic resources to exit.[41] Additionally, these ISOs/RTOs suggest that the capacity prices could settle at levels that are too low to attract new capacity not encompassed by externality payment programs[42] and, in the long term, could threaten resource adequacy.[43]

Externality payments, such as ZECs and RECs, reward the electricity production of certain resources, and in that way they affect outcomes in capacity markets. For example, externality payments may create incentives to install non-emitting generating capacity that meets state environmental objectives, and these resources would not be profitable without these payments. Entry of such new resources changes capacity prices and thereby affects entry and exit considerations for other generators. Externality payments can also affect exit and entry through changes to revenues in energy markets induced by new non-emitting generators. But, it is important to keep in mind that internalizing externalities improves economic efficiency. And, while detrimental welfare effects of externality payments on capacity markets are theoretically

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[37] PJM Filing, *supra* note 4.

[38] Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 2 (2018).

[39] *Pre-Technical Conference Comments, Robert C. Flexton, President & CEO, Dynegy Inc., Docket No. AD17-11-000*, FERC (Apr. 13, 2017), https://www.ferc.gov/CalendarFiles/20170426151233-Flexon,%20Dynegy.pdf.

[40] *ISO New England Inc.*, 162 FERC ¶ 61,205, P 4 (2018).

[41] The suggestion of externality payments negatively affecting the entry and exit decisions has been brought forward, among others, by ISO New England in its white paper stating that "the participation of resources with out-of-market contract revenue (…) depress capacity prices for all other capacity resources for many years. Further, this potential may impair the market's ability to attract new, competitively-compensated resources when they are needed ISO-NE." ISO New England, Competitive Auctions with Subsidized Policy Resources 6 (2017), https://www.iso-ne.com/static-assets/documents/2017/04/caspr_discussion_paper_april_14_2017.pdf. FERC explained in approving ISO-NE's change, "[a]ccording to ISO-NE, these out-of-market actions could result in price suppression and thus negatively impact the market's ability to retain and justly compensate needed existing resources and to attract new, competitively-compensated resources." Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 17 (2018); accord. PJM Filing, *supra* note 4.

[42] Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 4 (2018).

[43] According to ISO-NE, it favored this objective "because FCM's capacity clearing price guides competitive entry and exit decisions for the region," and therefore "is essential to achieving the region's resource adequacy over the long term." *ISO New England Inc.*, 162 FERC ¶ 61,205, P 32 (2018).

possible,[44] it is far from clear whether externality payments indeed have such detrimental effects on capacity markets, as we discuss in the remainder of this report.

Before implementing reforms of the capacity market reforms under the Federal Power Act, market operators[45] must demonstrate to FERC that any rates they propose to charge for interstate electricity are just and reasonable.[46] In order to satisfy the just and reasonable standard and avoid needlessly causing inefficiencies, ISOs/RTOs need to base their decisions on economic findings pertaining to their markets when altering their market designs. In addition, given the long lifespan of power generation assets, any unreasoned alteration in market design rules has the potential to result in a long period of inefficient outcomes. While there has been a substantial discussion around state policies and the functioning of wholesale markets,[47] both comprehensive economic modeling and empirical evidence are necessary to sufficiently demonstrate any destabilization of markets.

But there is currently no such evidence that externality payments threaten the efficient functioning of capacity markets, or that these capacity markets require reform. First, the argument for reforming capacity markets in reaction to externality payments focuses only on private generation costs, disregarding the external cost of electricity generation that is being addressed by the externality payments. This approach leads the proponents of reform to incorrectly identify which generators are economic and which are not, and they incorrectly claim that any price effect of externality payments would be inefficient. Second, the arguments for proposed reforms overlook the effect of the inherent market forces of capacity markets that, by design, would lead to price adjustments based on the supply and demand conditions in the market. Proponents of reform then incorrectly claim that externality payments would threaten either the functioning of the market or resource adequacy. And, finally, the arguments disregard the other important flaws of capacity markets that need to be addressed.

Externality payments help correct market failures and improve economic efficiency

As explained above, the external costs that electricity generation imposes on society are usually not priced in the energy markets. When such external costs, such as carbon emissions, are present, they should be taken into account when deciding whether or how much a resource should be used. Externality payments for generators' desirable attributes force the market to consider the external costs of various resources.

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[44] PJM's Market Monitor has explained that ZECs "are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall" and that "[t]he current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources." 2016 State of the Market Report for PJM, *supra* note 1, at 37. David Patton, the President of Potomac Economics Ltd., was more cautious when discussing the relevant state policies, acknowledging that "[s]ubsidized entry in itself is not necessarily problematic. For example, if subsidized entry simply displaces non-subsidized entry in similar quantities, it would have little effect on market prices, holding all else constant. Therefore, the problem is largely one of coordination and avoiding sustained disequilibrium conditions (i.e., capacity surpluses caused by the subsidized entry)." *Comments of David B. Patton, Ph.D., Regarding State Policies Affecting Eastern RTOs, Docket No. AD17-11-000*, FERC (Apr. 24, 2017), https://www.ferc.gov/CalendarFiles/20170426150115-Patton, Potomac Economics.pdf. In ISO New England some stakeholders expressed concern that allowing state-subsidized resources to participate in capacity markets without subjecting them to a minimum offer price rule could threaten the financial viability of other resources. *See* Sarah K. Adair & Franz T. Litz, Understanding the Interaction between Regional Electricity Markets and State Policies 9 (2017).

[45] Federal Power Act, 16 U.S.C. §§ 791-828(c), at § 824(e) (2010 & supp. 2010).

[46] *Id.* § 824d(a).

[47] For some of the contributions to the discussions, see FERC Dockets, *supra* note 1.

In particular, when a generator that would not have cleared an auction without a ZEC- or REC-style payment is able submit a bid that allows it to clear after the introduction of such a program, it does not imply that the payments distort competition or efficiency. Rather, it suggests that the presence of the generator is socially desirable when external attributes are considered. State policies that are directly related to socially desirable attributes should be seen as instruments that help fix this market failure and level the playing field. These payments introduce a difference in revenues between clean and emitting generators that aim to approximate the revenue that the resources would have gotten if the external costs of pollution were taken into account in the energy market. As such, a policy offering payments for clean attributes does not distort the market outcome but rather moves the market towards more economically efficient outcomes from a societal perspective.

It is a misguided approach to treat externality payments like distortive, rent-seeking subsidies that simply provide financial aid to a group of producers without being directly tied to a quantifiable external benefit. This misunderstanding may stem from the tendency to focus only on private costs when defining what it means to be an "economic" resource. Generators that receive externality payments, and clear the market, are indeed economic when considered from the perspective of overall social welfare. Even if externality payments are second-best policies, their corrective effects are desirable given the high external costs emitting resources impose on society.

Given that external costs of emissions are currently not fully internalized in markets, the external costs of externalities and, hence the level of existing market distortion can be very substantial. For example, the annual external damages associated with the climate change damages from CO_2 emissions of a typical 1,000 MW coal plant, not taking into account damages from other pollutants, would amount to about $234.3 million[48] based on the Interagency Working Group's Social Cost Carbon.[49] In comparison, PJM forecasted that a 1,000 MW seller in one of their areas would see its capacity market revenue reduced by $6.75 million annually given the effect of externality payments, a negligible amount compared to their external costs.[50] The external costs of emissions therefore starkly outweigh the reduction in generators' revenue, and suggest that the market signals sent by externality payments guide the generation mix in the right direction. Therefore, externality payments help correct existing market distortions, rather than exacerbate them. And misguided adjustments to capacity markets may cancel out those corrective effects.

Well-designed externality payments create changes in the generation mix that are similar to those induced by first-best pollution taxes. A first-best emissions tax would increase the marginal costs of energy generation of polluting units based on the external damages they cause, forcing them to bid higher in both energy and capacity markets. The average energy

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[48] An average coal plant operated with a 53.5% capacity factor in 2017. Electric Power Monthly, U.S. Energy Info. Admin. (2018), https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a (last visited Apr. 24, 2018). A typical coal plant has an average emission rate of 1 ton/MWh. Therefore, a 1,000 MW coal plant would produce 1,000*8760*53.5%= 4,686,600 MWh of electricity and about 4,686,600 tons of carbon dioxide. The monetary damages of these emissions equal to $234,300,000 in 2017 dollars using the Interagency Working Group's Social Cost of Carbon value of about $50 per ton in 2017 dollars. *See* Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, at 16 (2016).

[49] The Social Cost of Carbon measures and monetizes the damage that results from emission of a ton of CO_2 into the atmosphere. The Interagency Working Group's (IWG) 2016 Social Cost of Carbon estimate is the best currently available estimate for the external cost of CO_2 emissions. IWG's methodology has been repeatedly endorsed by reviewers. In 2014, the U.S. Government Accountability Office concluded that IWG had followed a "consensus-based" approach, relied on peer-reviewed academic literature, disclosed relevant limitations, and adequately planned to incorporate new information through public comments and updated research. *See* Gov't Accountability Office, GAO-14-663, Regulatory Impact Analysis: Development of Social Cost of Carbon Estimates 12-19 (2014), http://www.gao.gov/assets/670/665016.pdf.

[50] PJM Filing, *supra* note 4, *Attach. E, Aff. of Adam J. Keech*, at 3.

price would increase, but generators with higher emissions would clear the auctions less frequently and, when they clear, the most pollution-intensive resources would earn less per MWh. For example, under a first-best carbon pricing policy, the 1000 MW coal generator above would need to pay a tax equal to the damages it causes—the Social Cost of Carbon—and, hence, would face even a strong exit signal. Consequently, just as is the case with externality payments, profits fall for emitting resources to the point that some may be forced to exit the market.

The generators that leave the market under a pollution tax, but would not have left otherwise, are currently being classified as "economic" in many policy discussions. However, they are socially uneconomic when external costs are considered. Clean resources, on the other hand, do not need to increase their bids under pollution taxes or payment programs, because their marginal costs are unaffected. Therefore, they would clear the auctions more often and would receive higher prices for their generation. Consequently, their profits rise, which also leads to increased entry and slower exit of non-polluting resources, just as with the externality payments.[51]

Externality payments may increase the economic efficiency of entry and exit behavior

As discussed above, capacity market prices and energy market prices are interrelated. Because prices in energy markets are distorted due to negative externalities, current capacity prices are distorted as well. Thus, deviating from the prices that would have occurred without state policies does not automatically imply a worse outcome in terms of social welfare, and, thus, economic efficiency. Rather, if we measure from the perspective of overall societal welfare, those deviations would reflect better outcomes because the external cost of emissions would be partially internalized. After all, the introduction of first-best taxation of externalities—which, by definition, would lead to a socially efficient generation mix—would also lead to lower revenues for emitting resources and, thus, faster exit of those resources.

Externality payments are meant to improve price signals by supplementing the revenue of generators that offer societal benefits through their lack of emissions. They indirectly affect the profitability of polluting resources, both through energy markets and capacity markets. Polluting resources also enter less frequently and exit quicker than under a policy scenario without externality payments. This might in particular apply to coal- and oil-fired plants given their pollution intensity.[52] Indeed, the exit of the most polluting resources would likely be even higher under the first-best policy of emissions taxes. On the other hand, the prospect of additional revenues from the externality payments cause clean generators to bid lower than they otherwise would in wholesale energy markets, and make some new resources enter the market that otherwise

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[51] The similarity in the outcomes under taxation of externalities and payments to avoid externalities can be seen by analyzing a simple case of inelastic demand, one type of emitting generator and payments for attributes set at the value of avoided emissions. Here, the two policies are indistinguishable from the perspective of the generators as they lead to the same profits at the equilibrium. Let t denote the corrective tax rate, s the payment for clean attribute, x the amount of clean generation, y the amount of dirty generation, $MC_x(x)$ and $MC_y(y)$ the aggregate supply curves associated with the two types of generation, and *ext* the value of avoided emissions. The market solution under optimal tax is characterized by conditions: $x^t+y^t=Q$ and $MC_x(x^t)=MC_y(y^t)+t$. On the other hand, with payments for attributes the market will generate electricity such that: $x^s+y^s=Q$ and $MC_x(x^s)-s=MC_y(y^s)$. Whenever payment for clean attributes are set at the value of avoided pollution ($s=t=ext$) the solutions of those equations are the same: $x^s=x^t=x^*$ and $y^s=y^t=y^*$. As the market price in the tax case differs from the market price with payments for attributes by value of avoided emissions: $p^t=MC_x(x^*)=ps+ext$, the achieved profits are the same no matter which of the policies gets implemented. Consequently, as the two regimes are undistinguishable for generators in any period, their effect on dynamic incentives for entry and exit (and, thus, the capacity market) will also be the same. Clearly, in such a case the payments for attributes send exactly right signals to the resources. The current conditions at the energy market do not exactly match the conditions for profit equivalency described above. However, the results convey the intuition for similarities between corrective taxes and payments for attributes and can be seen as approximation of the actual outcomes.

[52] *See* Shrader, Unel & Zevin, *supra* note 29.

would not have entered. Therefore, the increased exit of some types of resources and the increased entry of others types of resources does not necessarily imply that the market is failing.[53]

Claims about distorted entry and exit generally remain vague about what exactly constitutes economic inefficiency and how to measure and compare it across different outcomes. These claims mostly rely on the differences in the types of resources that would enter and exit with state policies compared to the status quo.[54] However, it is not clear that externality payments decrease the economic efficiency of entry and exit behavior compared to a business-as-usual scenario. As we show below, establishing whether the entry of a given generator combined with the exit of another specific resource is more efficient compared to the status quo may be a challenging task. Even determining which of two possible entrants is more efficient from a societal point of view can be difficult.

Given that consumers' demand for electricity is largely fixed and the electricity market is competitive, choosing a socially efficient mix of generation resources is equivalent to picking a generation mix that minimizes the total social costs associated with energy generation, while maintaining the reliability of the system. To establish the true social cost of an existing resource, one needs to consider at least four types of costs associated with it: the marginal costs of energy generation, power plant cycling costs,[55] yearly operation and maintenance costs independent of generation, and costs associated with externalities. For new resources, the construction costs are also relevant.

Engineering literature uses a concept called "Screening Curves" to identify the socially efficient composition of generators. These curves show the average cost of using a plant's capacity to summarize the different types of costs, except for externalities.[56] One important lesson from engineering literature studies is that there is no one superior type of generator that is the most-efficient under every setting, but rather, the socially efficient choice of a new resource depends on many factors. For instance, a high-marginal-cost, low-fixed-cost resource will be less costly to operate than a resource with a low-marginal-cost, high-fixed-cost when both are expected to operate for a relatively low number of hours (at low capacity factors).[57] In other words, for defining what is "efficient," the totality of factors, including the properties of the existing generation mix, and, thus the capacity factors, must be considered.[58] In particular, a simple comparison of marginal generation costs, or going forward costs, will not make clear which generators are socially desirable.

Panel A in Figure 1 shows the private annual average cost of capacity usage for three types of generators dependent on their capacity factor. The costs are composed of the generators' annual fixed costs, given by the y-intercept, and variable costs, given by the slope of the screening curves.[59] In relative terms, the Gas Turbine (GT) generates power at the lowest

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[53] However, current externality payments disregard the pollution intensity of dirty resources. Consequently, these policies treat all polluting power plants the same way, while the first-best policy would have sent stronger negative signals for coal and oil-fired power plants than for gas generators. In other words, with the current system of externality payments, some gas generators might be likely to exit slightly too early and enter too little while coal plants might exit too slowly and enter too much, compared to the socially efficient outcome.

[54] Given that externality payments are not first-best policy tools to internalize environmental and public health externalities, there may be some dynamic inefficiencies associated with them.

[55] Cycling operations include on/off startup and shutdown operations, on-load cycling, and high frequency MW changes for automatic generation control.

[56] *See* Steven Stoft, Power System Economics: Designing Markets for Electricity (2002); Yusuf Emre Güner, *The Improved Screening Curve Method Regarding Existing Units*, 264 Eur. J. Oper. Res. 310, 310–326 (2018).

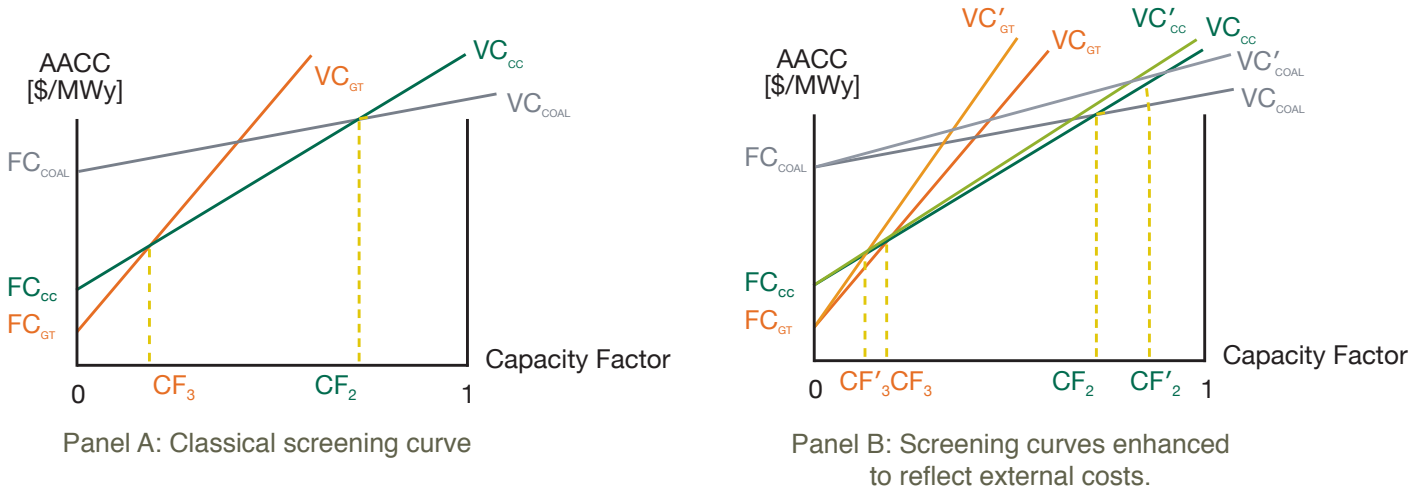
[57] For the intuition see Güner, *supra* note 56, at 311-312

[58] The amount of existing capacity as well as the proportion of generators of various types will determine how often a new resource of a certain category will be able to clear the energy market. This information can be summarized in form of capacity factor - the fraction of a generator's potential output that is actually produced. *See* Stoft, *supra* note 56, at 36.

[59] For the purposes of simplicity, the basic screening curves methodology is presented here that, for example, does not take into account dynamics of a power market.

costs among the other two if the power plant is run less than a certain amount of capacity factor, CF_3, annually. The Coal power plant would be the preferred choice if the new power plant is expected to operate actively over a capacity factor of CF_2. The Combined Cycle (CC) power plant is cost-effective if it runs at a capacity factor that is between CF_3 and CF_2.

Figure 1: Comparison of screening curves for various resources



Source: Figure 1 adapted from Yusuf Emre Güner, *The Improved Screening Curve Method Regarding Existing Units,* 264 EUR. J. OPER. RES. 310, 312, fig.2 (2018).

Source: Authors' adaptation of screening curves

When external damages associated with individual power plants are considered, the socially efficient generation mix changes. In Panel B, new screening curves reflect the social screening curves. Adding the external costs of pollution increases the marginal cost of production and, thus, rotates the screening curves outwards. The degree of rotation is smaller for cleaner generators and higher for dirtier generators. Here the CC power plant is depicted as having the lowest external damages, with the coal plant having the highest external damages. With the shift in curves, the thresholds for choosing the cost-efficient generators change. The "cleaner" CC generator is now the preferred resource for a wider range of capacity factors.

As is clear from the comparison of Panels A and B, focusing solely on marginal private costs in an analysis to determine what type of new generation is socially efficient would lead to misleading conclusions. A well-functioning capacity market would automatically induce efficient entry and exit of the resources. However, the current market design disregards externality costs, and thus cannot currently incentivize socially efficient entry and exit.

There is no credible evidence that externality payments threaten the viability of markets

Concerns that externality payments would inefficiently suppress capacity market prices, and that the resulting price changes would undermine the viability of markets, have been at the heart of the arguments in favor of capacity market redesign. But, currently there is no empirical support for this argument. Any price effect of externality is likely to be modest, especially in comparison to historical price fluctuations observed in the market and the social welfare gained from avoided emissions. In fact, given the interconnected nature of energy and capacity markets, and that other

generators would also adjust their bids, clearing prices might even increase under some conditions. In addition, capacity markets prices would, by design, adjust to meet the resource adequacy requirements if capacity was indeed scarce. Past evidence also shows that capacity markets have consistently achieved their goals of resource adequacy despite a plethora of subsidies and steep price fluctuations.

The actual effect of externality payments on capacity prices is likely to be rather modest for two reasons. First, not all resources receiving externality payments participate in capacity auctions. In some regions, like PJM, stringent capacity performance standards require bidding generators to guarantee sustained operation on an annual basis. Because renewable resources are seasonal, they would be unable to bid into capacity markets that have those restrictions. Externality payments to these resources consequently have only an indirect impact on capacity price formation—through the outcomes on energy markets.[60] Similarly, in ISO-New England, Minimum Offer Price Rules have been in place to prevent resources that receive externality payments from affecting the capacity market price.[61]

Second, even if resources that receive externality payments could participate in capacity markets, they would be limited in their ability to reduce capacity market prices. Any decrease in the bid of an infra-marginal unit that would have cleared the auction anyway, all else equal, would not affect the market clearing price. Thus, externality payments can affect the auction price only in limited situations: (1) when they induce entry (or prevent exit), increasing available supply of capacity, and hence lowering the market clearing price; or (2) when they directly lower the marginal bid, and hence the market clearing price.[62] For example, if the market clearing price were $40/MW, and if a resource that would normally bid $30/MW decreases its bid to $10/MW due to externality payments, the reduction in that resource's bid would not change the market clearing price.

Furthermore, given the interconnected nature of energy and capacity markets, even the direction of the net effect of the externality payments on capacity market prices is not clear. Polluting resources may submit higher bids than they would otherwise due to the prospect of decreased revenues from the energy market. Given that in some regions such polluting resources are more likely to be the marginal bidders in the capacity markets than the resources that get externality payments, the market clearing price in those regions might even increase depending on the resource mix of the area. Therefore, any forecasting exercise that adjusts the bids only for resources that get externality payments, or simulates auctions by only adding zero- or relatively low-priced supply bids without adjusting the other bids, is not sufficient to inform decisionmaking.

The actual outcomes in capacity markets also do not support claims that low or significantly-fluctuating prices do not send efficient incentives for entry, among others, to units that are not eligible for externality payments. States have long been using externality payments, and capacity prices have been fluctuating substantially since the introduction of the

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[60] For instance, from delivery year 2020/2021 PJM allows the resources only to bid under Capacity Performance standard which requires them to be able to sustain availability throughout the delivery year. In the first auction under the capacity performance standards only held in May 2017 wind and solar constituted only about 2 percent of capacity cleared. For analysis of the bidding results *see* Jeff St. John, *PJM's Latest Capacity Auction: A Tough Market for Nuclear and Demand Response*, GreenTech Media (May 24, 2017), https://www.greentechmedia.com/articles/read/pjms-capacity-auction-a-poor-showing-for-nuclear-and-demand-response#gs.uwVJzdo.

[61] An exemption was granted for 200 MW of renewable resources a year (or up to 600 MW if the exemption was not completely used in the previous two auctions).

[62] An externality payment might directly lower the marginal bid if it decreases either the bid of the unit that would be marginal without the payments or the bid of a units that would not clear the capacity auction without the payments.

capacity markets.[63] For example, the clearing prices in the PJM market, known as the Reliability Pricing Model (RPM), have varied widely since 2007 when the market was created. They started at $40.80 for delivery year 2007/2008 in the RPM Base Residual Auction, and have since fluctuated between $174 and $16.40 (see Figure 2). The last PJM auction featured a drop from $100 to $76.53.[64] Given the prevalence of such fluctuations in the market, it is very difficult to ascribe the cause of any changes in capacity prices to any one factor, without a proper econometric analysis. And, without a proper econometric analysis, it is hard to isolate whether capacity price fluctuations are due to state policies or to other changes in market conditions.

Figure 2: RPM Base Residual Auction Resource Clearing Prices within PJM over time and by sub-region (LDA)

Source: http://www.nrel.gov/docs/fy16osti/65491.pdf, p. 11.[65]

But, despite all of these fluctuations, a significant amount of new generation capacity continues to clear capacity actions. This is contrary to the argument that capacity markets are under threat. In PJM, for example, almost 3,000 MWs of new capacity, mostly in the form of new or uprates to existing gas-fired combustion turbine and combined cycle generation

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[63] Short lead time between the capacity auction and the delivery year could also lead to price fluctuations. A long lead time allows more types of resources to respond through entry to unexpected changes in capacity prices. Similarly, with a longer lead time, any possible effects of the externality payments will be smoothed out over time. But if a major plant announces plans to unexpectedly exit the market, in the next capacity delivery year, only certain types of power plants can be built in time to replace it and prices may fluctuate during that period. The amount of time needed to build a power plant varies by technology. For instance, the average construction time for nuclear reactors in the US has been 9.3 years, constructing coal power plants takes around four years and gas-fired power two to three years. *See* Michel Berthélemy & Lina Escobar Rangel, *Nuclear Reactors' Construction Costs: The Role of Lead-Time, Standardization and Technological Progress*, 82 Energy Policy 118 (2015). For instance, the average construction time for nuclear reactors in the US has been 9.3 years, constructing coal power plants takes around four years and gas-fired power two to three years. *See id.* at 20, tbl.4 ; *see* Executive Summary of *Projected Costs of Generating Electricity*, IEA, www.iea.org/textbase/npsum/ElecCostSUM.pdf (last visited Apr. 11, 2018).

[64] *See* PJM, 2020/2021 RPM Base Residual Auction Results PJM #5154776 (2017) [hereinafter "PJM 2020/2021 RPM Base Residual Auction Results"], http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx (summarizing results of auction).

[65] Thomas Jenkin et al., Nat. Renewable Energy Lab., NREL/TP-6A20-65491, Capacity Payments in Restructured Markets under Low and High Penetration Levels of Renewable Energy 12 (2016), http://www.nrel.gov/docs/fy16osti/65491.pdf.

units, cleared in the base residual auction for the 2018/2019 delivery year, nearly 5,400 MWs cleared for the 2019/2020 delivery year, and roughly 2,400 MWs cleared for the 2020/2021 delivery year.[66]

Importantly, capacity markets have co-existed for years with many different subsidies, both corrective and distortive, without leading to similar resource-adequacy fears. For example, fossil-fuel generators benefit from numerous federal tax deductions, including deductions for intangible drilling costs and for investment depletion related to oil and natural gas wells. In 2015, the U.S. government estimated that these subsidies amounted to $4.7 billion in reduced government revenue annually.[67] Additionally, many states have tax provisions in place that favor fossil fuels. For instance, Kentucky offers tax credits to electric-power entities operating coal-fired electric generation plants, alternative fuel facilities, or gasification facilities.[68] In Pennsylvania, the purchase or use of coal is exempt from the sales and use tax normally levied on sales of most goods and services in that state.[69] Independent reports quantifying federal and state fossil-fuel subsidies also tend to find substantial numbers.[70]

These subsidies similarly alter the outcomes of the wholesale markets, by lowering the revenue resources needed from the capacity markets. Yet, the effects of these non-market-payments on capacity markets have scarcely been discussed. Any change in market design in response to externality payments must be accompanied by an explanation for the different treatment of externality payments and fossil-fuel subsidies.

By design, capacity market prices would adjust to ensure resource adequacy

Another basis cited for reforming capacity markets has been that externality payments threaten resource adequacy. But, as we show below, externality payments do not pose any challenge for capacity markets fulfilling their main function. Even if the payments reduce the capacity prices, which, as we argue above, is not necessarily inefficient, they would still not undermine resource adequacy because of the design of the capacity markets.

Figure 3 shows a simplified depiction of PJM's capacity market. It presents the capacity supply curve and the capacity demand curve, called Variable Resource Requirement Curve. Because capacity demand is set by PJM, when PJM keeps the demand unchanged, the market clearing capacity price can decrease only if the supply of capacity increases and shifts the curve out as indicated by red arrows in Figure 2. In the context of externality payments, such a shift may happen if

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[66] Organization of PJM States, Inc. (OPSI), Recommendation that the PJM Board of Directors not Approve PJM Staff's Repricing Proposal for Filing at FERC (2018), https://citizensutilityboard.org/wp-content/uploads/2018/02/OPSI-BOD-Repricing-Letter-Final-with-vote.February.pdf; PJM, 2018/2019 RPM Base Residual Auction Results PJM #5154776, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-base-residual-auction-report.ashx (last visited Apr. 24, 2018); PJM 2020/2021 RPM Base Residual Auction Results, *supra* note 64.

[67] The number represents a nominal annual average figure based on the 10-year revenue estimate. *See* U.S. Office of Mgmt. & Budget, Progress Report on Fossil Fuel Subsidies, *available at* https://www.treasury.gov/open/Documents/USA%20FFSR%20progress%20report%20to%20G20%202014%20Final.pdf (last visited Mar. 29, 2018).

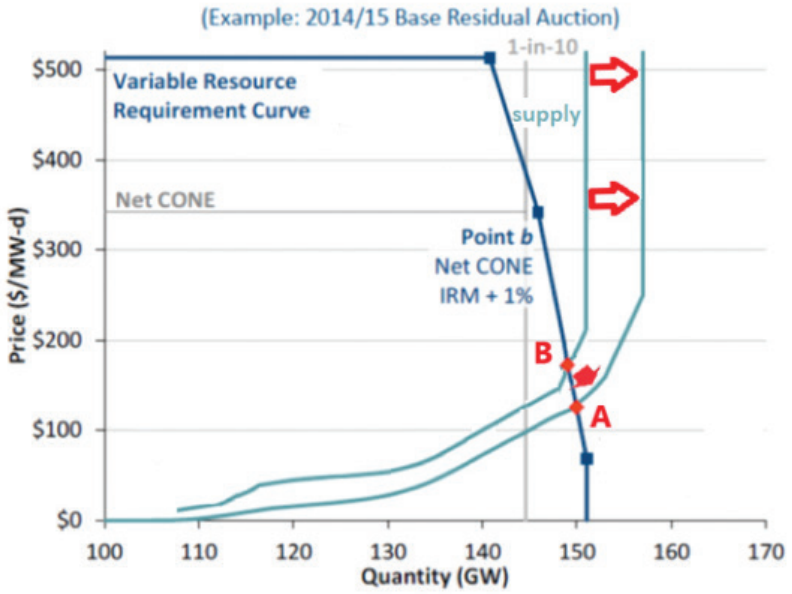
[68] *See Coal Incentive Tax Credit*, KY. Dep't of Revenue, https://revenue.ky.gov/Business/Pages/Coal-Incentive-Credit.aspx (last visited Apr. 24, 2018).

[69] PJM, Database, *Subsidies to Participants in PJM States, Based on Good Jobs First Subsidy Database*, https://earthtrack.net/sites/default/files/uploaded_files/20170605-item-02-subsidy-short-list-20170531.xls (last downloaded Apr. 24, 2018); *see also* Doug Dkoplow, *Subsidies to Suppliers in the PJM Interconnection Go to Fossil and Nuclear, Not Just Renewables*, EarthTrack (Jul. 20, 2017), https://earthtrack.net/blog/subsidies-suppliers-pjm-interconnection-go-fossil-and-nuclear-not-just-renewables (discussing these subsidies).

[70] For example, Oil Change International reports that United States federal and state governments gave away $20.5 billion a year on average in 2015 and 2016 in production subsidies to the oil, gas, and coal industries, including $14.7 billion in federal subsidies and $5.8 billion through state-level incentives. Janet Redman, Oil Change Intl., Dirty Energy Dominance: Dependent on Denial 5 (2017), http://priceofoil.org/content/uploads/2017/10/OCI_US-Fossil-Fuel-Subs-2015-16_Final_Oct2017.pdf.

existing clean resources that were previously unable to clear the market lowered their bids, or if new clean resources entered the market.

Figure 3: Capacity Supply and Demand in RPM



Source: Samuel A. Newell Pfeifenberger et al., *Third Triennial Review of PJM's Variable Resource Requirement Curve*, The Brattle Group (May 15, 2014), https://www.pjm.com/-/media/committees-groups/task-forces/cstf/20140630/20140630-item-04c-vrr-curve-background.ashx.

But, by design, the capacity market would react to those changes. A capacity market serves as a means of recovering fixed investment costs for many generators.[71] While lowered capacity prices will tend not to push the existing clearing generators out of the market,[72] they may discourage the entry of certain types of resources: namely, those resources for which the lower capacity price level, combined with expected profits from energy markets, would be insufficient to cover the investment costs. In the long term, such discouragement would change the supply curve, shifting it back to the left and thereby increasing capacity prices. Therefore, any decrease in price can continue only as long as there is a glut in capacity. Short-term shortage or surplus conditions, and resulting price changes, are only a natural result of market dynamics, and do not warrant market design changes.

With a properly constructed capacity demand curve, the capacity price automatically adjusts to reflect the costs of the new generators that are necessary for resource adequacy when supply becomes scarce.[73] Further, because the Variable Resource Requirement curve is updated every three years based on energy market revenues, it will shift up if energy market revenues go down, increasing the price PJM is willing to pay for any given level of capacity. In other words, capacity markets, by design, ensure that enough capacity is present to meet the highest demand in a given period. As a result, even if externality payments reduce capacity prices in the short term, capacity markets are designed to adjust to that change and keep prices at a level necessary to ensure resource adequacy.

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[71] Some of the resource might be able to fully recoup the investment costs through profits made at energy market.

[72] For existing clean generators, the investment costs are already sunk and even if the change in market conditions renders the full recovery of the initial capital costs impossible, staying in the market is still more profitable for them than shutting down if they can cover their variable costs, including their yearly maintenance costs, in the energy market.

[73] A separate question is how firms form expectations about the future capacity prices. If they expect the prices to fluctuate as described in the above paragraph, the initial discouragement effect will be much weaker.

Current capacity market designs exhibit flaws unrelated to externality payments that must be addressed

While externality payments do not threaten the capacity markets, there are other flaws in current markets that must be studied and addressed. In fact, as the U.S. Government Accountability Office recently concluded, the performance of capacity markets has not been well studied.[74] While FERC has conducted assessments of individual aspects of the market design, it has never fully assessed "how well the capacity markets have performed individually or overall relative to their objective of ensuring adequate resources at just and reasonable prices."[75] At the same time, "stakeholders continue to raise questions about the performance of capacity markets."[76] Nonetheless, it is clear that there are three categories of problems present in capacity markets today—all of which cause problems in capacity markets that are unrelated to externality payments. Yet, none are addressed by the reforms.

First, there is a capacity glut in many regions. For example, PJM's capacity auctions have led to commitments well above the required target reserve margin of 16.6%. For delivery year 2020/2021, though, a record-high reserve margin of 23.9% cleared the RPM Base Residual Auction.[77] That result represents a surplus-above-target margin of about 11,000 megawatts, which amounts to maintaining an extra 22 coal or gas plants (at 500 megawatts each) or 11 nuclear plants (at 1,000 megawatts each).[78] The ISO-New England annual capacity auction completed in February 2017 closed with the lowest prices since 2013 and ample reserves. ISO-New England has acknowledged this significant excess capacity.[79] Moreover, in both markets, many generators that do not clear the capacity auction still participate in the energy market.

Those numbers suggest that the amount of capacity operating in the market is inefficiently high. The capacity market needs time to adjust to design changes and many frequent changes create unclear signals. Therefore, in PJM, frequent changes in the design of the capacity market might have contributed to the oversupply. It is also possible that the design of the market, such as the lack of seasonality or an unnecessarily high Variable Resource Requirement Curve, exhibits deficiencies that cause the inefficiently high amount of capacity to be present. In any case, given this glut, price signals in the near future should either encourage exit of inefficient generators, rather than discourage it, or discourage entry of inefficient generators. Given this evidence, it is not clear why the potential price suppression effects of externality payments, if indeed present, is a cause for concern.

Second, the use of a Minimum Offer Price Rule (MOPR) in many regions is problematic. This rule imposes a minimum offer price for a new resource when the decisionmakers suspect that the resource would submit an "uncompetitive" low bid and thus artificially lower capacity auction clearing prices. MOPRs were initially designed to prevent the exercise of buyer-side market power. However, it is currently used widely and without any regard for market power issues. The

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[74] *See* U.S. Gov't Accountability Office, Gao-18-131, Electricity Markets: Four Regions Use Capacity Markets To Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance (2017), https://www.gao.gov/assets/690/688811.pdf.

[75] *Id.* at 49.

[76] *Id.* at 49.

[77] PJM 2020/2021 RPM Base Residual Auction Results, *supra* note 64.

[78] Jennifer Chen, *Got Clean Energy? Not So Much from PJM's Latest Auction*, Nat. Res. Def. Council (May 23, 2017), https://www.nrdc.org/experts/jennifer-chen/got-clean-energy-not-much-pjms-latest-auction.

[79] The grid operator needed to procure about 34,000 MW and wound up with more than 35,800 MW. *ISO New-England*, 162 FERC ¶ 61,205, P 38 (2018).

premise of a MOPR "appears to be based on an idealized vision of markets, free from the influence of public policies."[80] But as former FERC Chairman Norman Bay explained, markets are indeed affected by many different public policies.[81] Therefore, it is irrational to take action to address externality payments without also considering other subsidies. More recently, FERC Commissioner Richard Glick similarly criticized the application of MOPRs to resources receiving externality payments as "ill-conceived, misguided, and a serious threat to consumers, the environment and, in fact, the long-term viability of the Commission's capacity market construct."[82]

Additionally, a MOPR adjusts the bids deemed uncompetitive to the level determined by the levelized cost of construction net of a historical average of annual net revenue from sales of energy and ancillary services (Net CONE). However, the levelized Net CONE is not the economically rational capacity bid for a generator.[83] For a resource that is committed to being in operation in the given delivery year, for instance because it is already under construction, it would be optimal to submit its net going-forward cost or its opportunity cost, implying that the bid would be at a level lower than Net CONE. Thus, MOPRs fail in their attempts to create "competitive" bids by forcing the resource to submit a bid a higher than it would have bid even in the absence of externality payments, and penalizes the resources subject to a MOPR while inefficiently inflating the capacity clearing prices.

Particularly in ISO-NE, the MOPR prohibits some resources from clearing the market even though those resources will continue to stay in the market because of the externality payments they get from the states. Consequently, the capacity market may be sending signals about the relative scarcity of capacity, leading to new installations, despite enough generation being available on the market. MOPRs can therefore be seen as one of the main drivers of the overcapacity.

Third, the current designs do not address variations in seasonal peak loads. For example, PJM's extreme weather forecasts for the 2021-2022 season suggest that summer peak loads will exceed winter peak loads by over 25,000 MW.[84] Thus, capacity requirements needed to maintain resource adequacy are considerably larger in the summer than in the winter. However, the fact that PJM adopted a Capacity Performance requirement of year-round availability in its 2017 RPM auction implies that the market does not send the proper signal about when the additional capacity is needed. Combined with the seasonal character of some resources,[85] lack of seasonality creates an inefficiency—the market sends signals for investment in year-round capacity even though the existing year-round capacity combined with seasonal resources might be able to meet the demand at all times during the year.

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[80] *See* Modern Markets Intelligence, Inc., *Bay Picks Apart MOPR Concept on Last Day at FERC*, PowerMarketsToday (Feb. 7, 2017), https://www.powermarketstoday.com/public/Bay-picks-apart-MOPR-concept-on-last-day-at-FERC.cfm.

[81] *Id.*

[82] *See* Comm'r. Richard Glick, *Dissenting Comments about The ISO-NE Competitive Auctions with Sponsored Policy Resources Proposal Docket No. ER18-619-000*, FERC (Mar. 9, 2018) [hereinafter "Glick Dissenting Comments"], https://www.ferc.gov/media/statements-speeches/glick/2018/03-09-18-glick.asp#.Wr1p0q2ZPUo.

[83] *See* Wilson, *supra* note 24, at 29-32; *Post Technical Conference Comments of James F. Wilson, Docket No. AD17-11-000*, FERC (June 22, 2017), https://www.ferc.gov/CalendarFiles/20130911145022-Wilson%20Comments.pdf.

[84] Organization of PJM States, Inc., OPSI Resolution #2017-01, Demand Side Resource Participation in PJM Markets (2017), http://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20171010-opsi-letter-and-resolution-regarding-demand-side-resoruce-participation-in-pjm-markets.ashx?la=en.

[85] For example, the solar generation stronger in the summer than in the winter and thus has difficulty fulfilling the Capacity Performance year-round requirements.

Economic theory gives a clear reasoning for this inefficiency.[86] Economics prescribes that policymakers need to have at least as many policy tools available as they have targets.[87] As economic literature demonstrates, in capacity markets with at least two different seasonal maximum demand levels, which is tantamount to various capacity "targets," having just two instruments – a capacity price and energy price cap, cannot lead to efficient outcomes. Market designers should think of introducing other dimensions into their designs, such as capacity markets with targets that vary with location and season.

Additionally, as capacity price signals are less granular with respect to location and time relative to energy market price signals, decreasing energy prices means that resources like energy storage, demand response, and variable renewables would not receive any additional compensation for the additional benefit they provide in being able to provide energy in certain places and times.[88]

Understanding and addressing these flaws is imperative to the functioning of the capacity markets. Before moving forward with any more design changes that can potentially harm economic efficiency, it is important to recognize the root cause of any observed outcomes, and to address those causes directly.

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[86] *See* Paul Joskow & Jean Tirole, *Reliability and Competitive Electricity Markets*, 38 RAND J. Econ. 60, 60–84 (2006).
[87] *Id.* at 75; *accord* Jan Tinbergen, On the Theory of Economic Policy (2d ed. 1952).
[88] Chen, *supra* note 6.

Current Capacity Market Reforms

Reforms currently underway in ISO-NE and PJM do not solve the underlying problems in wholesale markets. Further, they might even fail to achieve the stated goal of these reforms—inducing efficient entry—while creating other distortions to economic efficiency.

First, externality payments for resources are based on their energy generation, rather than on their capacity. As such, any potential inefficiency associated with these payments, if they exist, would be directly connected to the energy market. Reforms suggested in PJM and ISO-NE, however, are aimed at reforming only the capacity market, without addressing the key underlying issues that prompted the externality payments in the first place—the fact that current energy markets fail to achieve economically efficient outcomes due to the presence of externalities. And a policy that counteracts the impact of the externality payments would just reverse the attempts to internalize those external costs.

A more desirable approach to reforming wholesale markets to address externalities is being taken by New York ISO (NYISO). NYISO is currently considering the introduction of a charge for CO_2 emissions in the energy market.[89] Such a charge would automatically level the playing field among various generators depending on their emissions intensity, without the need for resource-specific attribute payments.[90] NYISO's approach therefore directly targets the source of the inefficiency in the energy markets—the externality—and it is therefore a superior approach to any of these capacity market reforms.

Second, the reforms may not achieve the intended goal of incentivizing efficient entry. Reforms try to achieve the goal of keeping capacity prices elevated in the presence of externality payments. Higher capacity prices will, if all other things are held constant, reduce the incentives for existing generators to leave the market and increase the incentives for entry. Thus, the increase in capacity prices will increase the supply of available capacity. However, it is not currently clear whether the increase in capacity will be achieved by slower exit of existing generators, faster entry of new resources, or a combination of both. Thus, it is not even clear that attempts to modify capacity markets in order to keep capacity prices high, in response to the introduction of externality payments, would lead to more entry as desired by the ISOs/RTOs.

Without knowing which type of resource is the most responsive to capacity prices, it is hard to know the relative magnitudes of the changes in entry and exit behavior. If, for example, older and higher emitting resources are most price responsive, and if these types of generators usually set the price in capacity markets, then an increase in the prevailing capacity prices would lead them to stay in the market longer. As a result, the existence of this additional capacity that would not have stayed in the market otherwise, would lower the clearing price in the capacity market, partially counteracting the goal of the market redesign proposal. In addition, if these resources stay in the market longer than they otherwise would have now that the capacity prices are higher, they increase the available supply for the energy market, leading to a decrease in the energy prices. Because many resources rely mainly on energy market revenues, such potential for reduced revenue

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[89] For additional information on planned carbon pricing in New York see N.Y. Indep. Sys. Operator, Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals (2017), http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf

[90] With a carbon charge the generators still do not have incentives to internalize the external costs associated with local pollutants such as SO_2 or NOx.

might lead to a decrease in the entry rates, which would contradict the goals of market operators. Importantly, because the clean resources rely on the energy revenue more heavily than on capacity payments, a redesign not only might fail to attract entry, but could also additionally undermine states' efforts in addressing externalities.

Whether the higher entry rates or slower exit rates would be the main driver of the capacity increases depends on the characteristics of the market participants, in particular their costs of going forward, marginal costs of energy generation, and investment costs for the potential entrants. A simple scenario analysis with added resources that get externality payments would not be sufficient to understand the implication of externality payments on market outcomes, or on entry and exit incentives. A sophisticated modelling of the interconnected capacity and electricity markets, including the explicit consideration of formation of expectations concerning future periods, would be needed to determine the effect of the reform proposals and whether they would indeed lead to increased entry. Such modeling necessary to inform decisionmaking has not been done.

Third, each of the reforms would create additional distortions and harm economic efficiencies in different ways, depending on the specifics of the designs. Below, we review the reforms that are being discussed, and explain economic inefficiencies caused by each of the three reforms.

PJM's capacity repricing proposal

PJM is considering two proposals: a two-stage capacity repricing proposal and an Extended Minimum Offer Price Rule (MOPR-Ex).[91] The capacity repricing proposal introduces a two-stage auction. The first stage of the auction determines which resources clear the capacity auction based on the initial bids submitted by each resource.[92] The second stage, in which the initial bids of the resources are substituted with PJM-determined "competitive" bids, determines the price to be paid to all the resources cleared in the first stage.[93] PJM argues that the two-stage capacity pricing proposal scheme would raise the capacity prices to a level reflecting the bids that would have been offered without externality payments and hence would administratively adjust subsidized resource offers to prevent capacity price distortions.[94]

There are several reasons why PJM's two-stage capacity repricing proposal would hurt economic efficiency. First, adding a second stage to the current auction design will change generators' bidding behavior for the first stage auction. As we explained in Section I, the current auction design contributes to economic efficiency by giving generators the incentives to bid their true costs of staying in or entering the market. However, when a second-stage, in which the price is adjusted upwards, is added to the current design, the first-stage incentives of the generators change. Knowing that the final price will be adjusted upwards, generators might offer their capacity at prices below what would have been their "truthful" bid. While such bidding behavior does not necessarily lead to inefficiency under every circumstance, the equilibrium outcome of the bidding can no longer be guaranteed to be efficient.[95]

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[91] PJM filing, *supra* note 4.

[92] PJM filing, *supra* note 4, at 51.

[93] PJM filing, *supra* note 4, at 51.

[94] PJM, *Capacity Market Repricing Proposal*, (June 29, 2017), http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20171016/20171016-pjm-executive-summary.ashx

[95] Inefficiency may happen when generators have differing beliefs about each other's bids. In such a case their submitted bids may lead to more expensive generators clearing the market while the cheaper ones lose the auction. It is also possible with the shading that the adjusted price will not cover the true costs of generators. *See* Paul Milgrom, *Auctions and Bidding: A Primer*, 3 J. Econ. Perspect. 3 (1989) (for introductory discussion about the efficiency and information available to bidders).

Second, the price that is determined in the second stage will no longer show the willingness-to-pay for the incremental reliability benefit for a given level of available capacity in the market as determined by PJM's capacity market demand curve. Even though this demand curve is administratively designed and set, bifurcating how the prices and quantities are determined ignores the logic of the demand curve.[96] The second-stage price would reflect the willingness-to-pay for additional capacity as if the sponsored resources were offering capacity at the PJM-specified prices, often making them look prohibitively expensive. But, if the offers were indeed this high, and, hence, the supply curve truly corresponded to the supply curve PJM would use in the second-stage auction, the PJM-determined downward sloping demand curve would have led to a lower level of contracted capacity at the equilibrium than the amount that cleared the first-stage auction. This result highlights the basic logic of a downward-sloping demand curve—the actual willingness-to-pay for the additional capacity decreases with the amount of cleared capacity because the incremental reliability benefit of additional capacity, given the level of available capacity, is lower. The repricing approach completely decouples the quantity of the contracted capacity from the benefits associated with it. As a result, the bifurcation will lead to higher prices for a given level of capacity, thereby increasing the prices consumers pay, but also undermining the logic behind the design of demand curve. Any justification for the elaborately chosen shape of demand curve would be lost if such a proposal is implemented.[97]

PJM's reasoning that the proposal would "maintain the correct price signal"[98] by restoring the prices that would have resulted in a world without externality payments by adjusting only the bids of units that gets these payments is also misguided. Emitting resources might already be taking other firms' externality payments into account in their current bids. Given that clean resources are usually characterized by low marginal cost of energy generation, their presence in the market already substantially reduces the profits of emitting resources in energy markets. Because the capacity and energy markets are strongly interrelated, emitting generators' capacity bids should already reflect the profits lost on the energy market and be higher compared to a scenario without externality payments. Therefore, a counterfactual analysis that adjusts only the bids of the resources that get externality payments, and not others, would not correctly simulate what would have happened without these payments. PJM's "correct price signal" is bound to be higher than the counterfactual price that would have been reached in a hypothetical market without any state policies.

The effect of capacity repricing on PJM's emissions would depend on how various types of resources respond to increases in capacity prices. Under the likely scenario that inflated capacity prices prolong the economic life of emitting resources while having no (or low) impact on the entry of clean resources, total emissions would rise. On the other hand, should the higher capacity price attract new zero-emission resources, the redesign of the market would decrease emissions.

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[96] Levelized net cost of new entry (Net CONE) serves as a reference point for constructing the capacity demand curve. It is the estimated nominal levelized fixed costs of entry based on a 20 year asset life of a combustion turbine net of estimated energy and ancillary service margins. PJM states that: "In designing the VRR Curve, PJM seeks to ensure that the amount of capacity it procures satisfies a loss of load expectation of one event in 10 years. The price axis of the VRR Curve contains multiples of the Net CONE value, and the megawatt quantity axis contains the target reliability requirement. Higher prices (above Net CONE) are associated with capacity shortage conditions and lower prices are associated with excess capacity conditions", Order on Rehearing and Compliance, *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,035, P 1 (2015), https://www.ferc.gov/whats-new/comm-meet/2015/101515/E-23.pdf.

[97] *See* for example Triennial Review of VRR Curve Shape (June 2014) *available at* https://www.pjm.com/-/media/committees-groups/task-forces/cstf/20140630/20140630-item-04c-vrr-curve-background.ashx

[98] PJM Filing, *supra* note 4, at 1.

PJM's Extended Minimum Offer Price Rule

The Extended Minimum Offer Price Rule (MOPR-Ex), on the other hand, would extend the existing MOPR by applying it to all existing and new resources that will receive revenue outside of the market, regardless of the resource types, while providing a narrowly-defined renewable portfolio standard exemption.[99] PJM's Independent Market Monitor, which originally suggested the MOPR-Ex, argues that the MOPR-Ex would "preserv[e] the efficient market outcomes and accurate signals for entry and exit that are necessary for well-functioning and competitive markets."[100]

However, the MOPR-Ex would cause all the standard problems that have been raised related to any MOPR. In particular, it will cause excess capacity because it disregards some of the already existing capacity in the market. And, it leads to consumers paying twice for available capacity through (1) higher prices in the capacity markets and (2) externality payments through state programs.[101]

The MOPR-Ex will prevent some of the clean resources from clearing the market because they receive revenue outside the market, while strengthening the incentives for entry by sustained high prices. If some of the resources that are subject to the MOPR-Ex decide to stay in the wholesale markets even after failing to clear the capacity market, there will be excess capacity, reducing the prices in the energy market.[102] As lower energy prices will lead to lower energy revenues for all resources, all existing resources, even those that are not subject to the MOPR-EX, will need to bid higher in capacity markets to recover their net expected costs of going forward. The "counterfactual" prices—capacity prices that would have been reached in the absence of state policies—will thus not be restored.

In addition, with the MOPR-Ex, total capacity costs will be inefficiently high. Consumers will have to pay for operation and maintenance costs of the excess capacity as well as additional investment costs of the new units that are not really required to ensure the system's reliability.

If the MOPR-Ex leads to some zero-emission resources exiting, or not entering the market in the first place, it also will counteract the goals of state policies or make it costlier for states to achieve their goals. Because resources subject to the MOPR-Ex cannot get capacity market revenues, they will have to rely on energy market revenues and externality payments. If, for whatever reason, energy market revenues fall, states may have to increase externality payments to achieve their environmental goals. Such an increase in externality payments would not only make it inefficiently costly for states to achieve their goals, but would increase the amount "out-of-market" revenues that parties were so concerned about at the beginning of the process. Thus, a MOPR should be used only for the narrow circumstances for which it was originally intended—preventing the exercise of buyer-side market power—but not for "accommodating" or "mitigating" state environmental and public health policies.[103]

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[99] PJM filing, *supra* note 4.

[100] *Id*, at 1.

[101] *See* ISO New England Inc., ER18-619-000, Revisions to ISO-NE Tariff Related to Competitive Auctions with Sponsored Policy Resources 3 (January 8, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/er18-619-000_caspr_filing.pdf.

[102] In particular, the prices during the (super-)peak time will be squeezed. *See* the discussion in section X on the interdependence between outcomes on capacity and energy markets.

[103] Though the minimum offer price rule began as a reasonable effort to combat "true attempts to exercise buyer-side market power," recently, it has "morph[ed]" into "an examination of whether states have provided support or a subsidy to a resource that is selling into the capacity market." Order on Rehearing, *ISO New England Inc.*, 158 FERC ¶ 61,138, 892 (2017) (Bay, C., concurring); *see* Glick Dissenting Comments, *supra* note 82.

Zero-emission resources that receive externality payments but do not qualify for the narrowly defined renewable portfolio standard exemption will potentially not receive any capacity revenue, and will thus be harmed. Additionally, with a MOPR leading to overbuilding of capacity, the energy revenue of zero-emission resources will, all other things held constant, fall as well. Therefore, units subject to a MOPR will see their relative competitiveness and profitability decrease, leading to a slower entry of clean resources and a slower rate of emission reductions. But, it is not clear how the redesign will impact the zero-emission resources exempted from a MOPR. The effect and thus the change in emissions will depend on their responsiveness to the price changes relative to the price responsiveness of polluting resources.

ISO-NE's Competitive Auctions with Sponsored Policy Resources

ISO-NE also proposed a change, which FERC recently approved.[104] That proposal, known as Competitive Auctions with Sponsored Policy Resources (CASPR), allows new generators that receive externality payments (or "sponsored policy resources" as defined by ISO-NE) to enter the capacity market when those generators replace the older existing capacity resources that are willing to exit. To coordinate the entry of new resources and the exit of existing resources, CASPR introduces a new substitution auction that runs immediately after the regular capacity auction. The substitution auction settles at a clearing price differently than the regular capacity auction, based on the new supply capacity of "sponsored policy resources" and the capacity of existing resources that are willing to exit. This price is then paid to the new resources by retiring resources to take over the obligations assigned in the initial auction. Therefore, the retiring resources receive revenues based on the difference between the higher price in the primary auction and the lower price in the substitution auction as a "severance" payment to leave the market.[105] The new sponsored policy resources receive the lower price in the substitution auction, while new resources that are not state-sponsored receive the higher price in the primary auction. [106]

Prior to CASPR, ISO-NE applied a MOPR to new capacity resources and required the "sponsored assets" to bid at their unsubsidized cost.[107] Its rules allowed for a limited exemption for certain types of renewables to address states policies. Given that the application of a MOPR is in itself problematic, modifying rules to allow for more participation from resources that get externality payments was desirable. CASPR, however, only partially achieves that goal at the cost of bringing new distortions to the market.

With CASPR, new resources that receive externality payments will still be subject to a MOPR in the primary auction. However, they will be allowed to participate in the substitution auction without a MOPR if they could otherwise not clear the primary auction. Thus, these new resources will be able to receive capacity payments only if they can clear the substitution auction, which is intended to coordinate the entry of new policy resources with the exit of existing resources that are willing to "buy out" their obligation and retire.[108] As a result, this setup implies that the rate of entry from resources that receive externality payments will hinge on the willingness of existing plants to exit, without regard for states' preferences. Furthermore, CASPR considers a clean resource to be "new" as long as it does not clear the substitution auction. This means that, in an extreme case where no existing resource is willing to exit the market, ISO-NE would treat that resources as "new" throughout its entire physical life, always subjecting it to a MOPR.

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[104] *See* Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 4 (2018).

[105] *See Competitive Auctions with Sponsored Policy Resources (CASPR) Key Project*, ISO New England, Inc., https://www.iso-ne.com/committees/key-projects/caspr/ (last visited Mar. 29, 2018).

[106] The sponsored policy resources can also bid into the primary auction but they would be subject to MOPR, and thus less likely to clear.

[107] ISO New England, Inc., *supra* note 105, at 2.

[108] The Renewable Technology Resources exemption will be phased out within the next 3 years.

In addition, the proposal will lead to distorted incentives, both for existing resources close to retiring and for new resources that do not get externality payments. The existing generators that may be willing to retire will have incentives to distort their bids in the primary auction. Without the substitution auction, the generator would have earned the difference between the primary auction price and its net cost of going forward. The substitution auction, however, creates a new revenue potential. If an existing resource clears the substitution auction and exits the market by transferring its obligations to a new resource, it would earn the difference between the primary auction price and the substitution auction price. Therefore, if the price in the substitution auction is lower than the cost of going forward for a resource, that resource would be better off if it clears the primary auction, participates in the substitution auction and transfers its obligations to a new resource. The possibility of higher earnings through the substitution auction will create incentives for resources to lower their primary auction bids enough, even below their costs of going forward, to ensure that they clear. As a result, if resources expect that the substitution auction price will be lower than their own cost of going forward, they will submit low bids in the primary auction. Again, because resources are no longer incentivized to bid their marginal costs, the efficiency of the primary auction results can no longer be guaranteed.

Further, the final mix of resources in the market may not even be the cost-minimizing capacity mix. By design, the first stage considers the generators receiving externality payments only at price levels above the MOPR. However, capacity clearing prices are usually far below MOPR floor prices. Consequently, when the bids of some resources are mitigated, the prices may indicate capacity scarcity, sending signals for entry, despite enough capacity being present in the market to guarantee resource adequacy. New emitting resources may clear the primary market as long as they bid lower than the MOPR, leading to inefficiently high costs.[109] Therefore, CASPR might lead some of the existing capacity to retire based on the revenue from the substitution auction, even if that capacity would have been considered economic in the previous setting based on going-forward costs. It would do so while allowing new resources that have higher costs, and hence would not have been economic in the previous setting, to enter and clear the market.[110]

CASPR forces the new sponsored policy resources to participate in the substitution auction where, by design, the clearing prices are lower than in the primary auction. In this way, CASPR curtails the revenue of clean resources compared to emitting generators. The reduced competitiveness of the sponsored policy resources will lead to higher pollution levels than those that would occur with regular, one-stage capacity markets.

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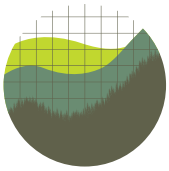
[109] For a discussion, *see* Motion to Intervene and Protest of the ISO-New England External Market Monitor, Docket No. ER18-619-000, *Revisions to ISO New England Transmission, Markets and Services Tariff Related to Competitive Auctions with Sponsored Policy Resources* (Jan. 30, 2018), https://www.potomaceconomics.com/wp-content/uploads/2018/03/EMM-Protest-FERC.pdf.

[110] *Id.*

Conclusion

Wholesale market operators have begun considering and implementing several proposals to reform capacity markets in order to counteract the feared impact of state-level externality payments. These proposals are misguided for two important reasons. First, the proposals are based on the unfounded premise that externality payments have or will cause inefficient capacity-market distortions. Externality payments help internalize externalities, and thus help improve economic efficiency. And, to the extent that externality payments have affected the market, this is the natural effect of policies that help internalize the cost of carbon pollution.

Second, there is no sound evidence that state-level externality payments cause economically inefficient distortions to capacity market prices or that they harm resource adequacy. To the contrary, capacity markets continue to be marked by over-supply. Capacity markets are designed to ensure resource adequacy, and will adjust according to changing conditions in the market. Reforms that aim to counteract externality payments will bring new distortions to the market at the cost of states' ability to combat climate change.



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The Dark Side of DG: Addressing the Environmental Impacts of Dirty Distributed Generation

FOR

10:15 a.m. – 11:35 a.m. **ADVANCING ENERGY POLICY**

- **Kathleen Frangione**, Chief Policy Advisor, Office of the Governor for the State of New Jersey
- **Cheryl LaFleur**, Commissioner, Federal Energy Regulatory Commission
- **Andrew G. Place**, Vice Chairman, Pennsylvania Public Utility Commission

Moderator: **Burcin Unel**, Energy Policy Director, Institute for Policy Integrity

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THE DARK SIDE OF DG: ADDRESSING THE ENVIRONMENTAL IMPACTS OF DIRTY DISTRIBUTED GENERATION

MATTHEW CHRISTIANSEN* AND ANN JAWORSKI**

* J.D. Yale Law School, 2012. This Article was written while Mr. Christiansen was an Energy Law and Regulation Fellow at the Frank J. Guarini Center on Environmental, Energy, and Land Use Law at New York University School of Law. The Article grew out of a research project conducted along with Elizabeth B. Stein, whose input and many helpful comments were instrumental in shaping the final project. In addition, thanks are due to Danielle Spiegel-Feld, Jim Tripp, and Katrina Wyman. Any errors are, of course, our own.

** J.D. New York University School of Law, 2017. Clerk for Judge Richard Posner and Judge Frank Easterbrook, United States Court of Appeals for the Seventh Circuit, 2017–18.

INTRODUCTION

Distributed generation (DG) is playing an increasingly important role in the United States electricity sector. Although there is no single accepted definition of "distributed generation," the term generally encompasses small generating units that produce power for consumption at or near the facility at which they are located.[1] Depending on the exact definition, DG can include internal combustion engines, gas turbines (a category that includes relatively efficient combined-heat-and-power turbines [CHP], when those are fired by natural gas), wind turbines, photovoltaic panels, and fuel cells, among other technologies.[2]

Several reasons explain the growth of DG. DG can provide a variety of benefits, both to the owner of the DG unit and to the electricity grid. For example, electricity from DG can be significantly less expensive to consume than that from the marginal centralized generating station. Under these circumstances, using DG can decrease the cost of electricity for both the owner of the DG unit and also for the public at large. In addition, because it is distributed, DG can help respond to outages and other failures of the electricity distribution system as a whole.

Government policies in the United States have also helped fuel the growth of DG. These include policies such as demand response programs and tax incentives for certain types of DG, both of which compensate DG for its economic and reliability benefits. Together these policies create an incentive to install new DG units and to run already-installed DG units more frequently. In addition, some states have begun proceedings aimed at further increasing DG's role in their electricity generation mix. New York State's Reforming the Energy Vision proceeding (REV), which seeks to make DG a central component of a reformed electricity

1 *See, e.g.*, Order Adopting Regulatory Policy Framework and Implementation Plan, Case No. 14-M-0101 (N.Y. Pub. Serv. Comm'n Feb. 26, 2015), app. b at 14–15 [hereinafter REV Track One Order] (defining "distributed generation"); Thomas Ackermann, Göran Andersson & Lennart Söder, *Distributed Generation: A Definition*, 57 ELECTRIC POWER SYS. RES. 195 (2001).

2 *See* Guido Pepermans et al., *Distributed Generation: Definition, Benefits and Issues*, 33 ENERGY POL'Y 787, 791 tbl.1 (2005).

distribution model,[3] is the leading example. Although other states may not replicate New York's extensive support for DG, a number of other states desire to increase their use of DG.

DG's potential economic and reliability benefits are substantial, but the health and environmental impacts of DG are less clear. On the one hand, DG that is powered by non-emitting resources produces neither conventional pollutants, such as nitrogen oxides (NO_x) and particulate matter (PM), nor greenhouse gases (GHGs). And some types of fossil-fuel-fired DG can be more efficient than the marginal central generating station. Accordingly, increased reliance on low-emitting forms of DG can reduce the aggregate emissions associated with electricity generation.

On the other hand, many forms of DG, especially older DG that runs on diesel fuel, can emit pollutants at rates per kilowatt hour of electricity generated that far exceed even coal-fired power plants, which are generally the dirtiest form of electricity generation. In addition, unlike central generating stations, DG is often located near, or even within, population centers and most forms of DG lack an effective means of dispersing the pollutants emitted.[4] As a result, even a small increase in high-emitting DG can have significant health and environmental impacts.

Although the economic and reliability benefits of DG have received considerable attention in the legal literature, its environmental implications have gone comparatively unstudied. This Article fills that gap. It examines how current regulations address the environmental and health effects of increased DG as well as potential reforms that states and municipalities can take to mitigate the effects of relatively dirty DG.

In short, current federal, state, and local regulation of DG addresses the environmental and health effects of DG, but only partially. In particular, these regulations generally focus on only the emissions from an individual DG unit. That is, they do not directly regulate the interaction of DG units, leaving open the possibility that a high concentration of poorly controlled DG in a small area could create significant adverse health effects. These

3 *See* REV TRACK ONE ORDER, *supra* note 1, app. b at 14–15.

4 *See* Zheming Tong & K. Max Zhang, *The Near-Source Impacts of Diesel Backup Generators in Urban Environments*, 109 ATMOSPHERIC ENV'T 262, 262 (2015).

concerns are especially acute because a number of state and federal electricity-sector regulations, including, but certainly not limited to New York State's REV proceeding, may encourage the installation of multiple DG units in relatively small geographic areas. In addition, the current suite of regulations largely exempts small DG units from mandatory emissions standards, meaning that there is little regulation of these units. Although DG—especially small DG—generates much less electricity than central generating units, the laxer controls applicable to these units may exacerbate the health and environmental risks of concentrated DG. Moreover, existing regulations generally do not address GHG emissions from DG, and could create unintended incentives for increased use of inefficient DG.

There are, however, a variety of policy approaches available to address these concerns. These range from source-specific emission limits to market-based caps linked to the ambient level of various localized pollutants. This Article identifies a number of different approaches that regulators may consider in deciding how to address an increase in DG emissions. The relative merits of these policies will vary considerably based on the DG profile of different jurisdictions. Accordingly, this Article does not identify a single best approach for addressing the environmental and health impacts of DG. Instead, it lays out a menu of policy options to consider in deciding how to respond to the specific challenges that DG poses within a particular jurisdiction.

This Article proceeds as follows. Section I describes the increasing importance of DG to the U.S. electricity sector. Section II focuses on the environmental costs and benefits of DG. Section III briefly summarizes the current environmental regulations governing DG with an emphasis on the regulation of diesel-fired DG in New York State. Section IV outlines policy options available for addressing the environmental impacts of DG.

I. THE INCREASING IMPORTANCE OF DISTRIBUTED GENERATION

DG is playing an increasingly important role in U.S. electricity markets.[5] The rise of DG is the result of many factors,

[5] For a discussion of the rapidly increasing role that DG is playing in the commercial sector, see, for example, DELOITTE, DELOITTE RESOURCES 2015 STUDY: ENERGY MANAGEMENT PASSES THE POINT OF NO RETURN (2015), http://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-er-

including high electricity prices, the decreasing cost of solar panels, and the increasing demand for highly reliable electricity service.[6] By reducing demand for electricity from the grid at peak times, DG can reduce electricity prices—both for DG owners and other consumers who benefit from the reduction in aggregate electricity demand, which results in lower wholesale electricity prices overall.[7] Similarly, because much of the electricity produced by DG is consumed on-site, it reduces grid congestion and minimizes line losses (electricity lost during the transmission and distribution process), both of which can help reduce the total cost of electricity.[8] In addition, DG can help mitigate the effect of blackouts and other grid failures, leading to a more stable and resilient electricity system.[9]

Federal and state policies have also encouraged the growth of DG.[10] At the federal level, these policies include tax credits for certain forms of DG—especially those powered by non-emitting resources—and the promotion of wholesale-market demand response, in which customers receive a payment for reducing their electricity consumption from the grid at times of peak demand.[11] Although demand response programs are not aimed at supporting DG *per se*, a significant share of demand response providers

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6 *See* Pepermans et al., *supra* note 2, at 788–89; REV Track One Order, *supra* note 1, at 12–25.

7 *See* FED. ENERGY REGULATORY COMM'N, THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION, at 3–5 (2007), https://www.ferc.gov/legal/fed-sta/exp-study.pdf.

8 *See id*. at 3–8.

9 *See* Pepermans et al., *supra* note 2, at 794.

10 *See* N.Y. INDEP. SYS. OPERATOR, A REVIEW OF DISTRIBUTED ENERGY RESOURCES (2014) (discussing state and federal policies affecting the growth of distributed generation); Severin Borenstein & James Bushnell, *The U.S. Electricity Industry After 20 Years of Restructuring* 23–24 (Nat'l Bureau of Econ. Research, Working Paper No. 21113, 2015), http://www.nber.org/papers/w21113.pdf (discussing the effect of state and federal policies on the growth of photovoltaic solar DG in particular).

11 *See* NE. STATES FOR COORDINATED AIR USE MGMT., AIR QUALITY, ELECTRICITY, AND BACK-UP STATIONARY DIESEL ENGINES IN THE NORTHEAST 5–6 (2014), http://www.nescaum.org/documents/nescaum-aq-electricity-stat-diesel-engines-in-northeast_20140102.pdf/ [hereinafter NESCAUM REPORT] (discussing the effect of wholesale-market demand response on behind-the-meter generators); *see also, e.g.*, *Residential Renewable Energy Tax Credit*, ENERGY.GOV, https://energy.gov/savings/residential-renewable-energy-tax-credit (last visited Oct. 1, 2017) (describing certain federal tax credits for systems that produce renewable energy).

decrease their consumption of electricity from the grid and replace it with electricity generated from DG.[12] Demand response payments thus provide a significant source of compensation for DG units. In 2016, the U.S. Supreme Court upheld the Federal Energy Regulatory Commission's jurisdiction over demand response in wholesale electricity markets—a decision that will likely provide a significant boost to demand response, including demand response backed by DG.[13] In addition, the Federal Energy Regulatory Commission has recently approved proposals filed by wholesale electricity market operators to allow "behind-the-meter" resources (a category that includes DG) to sell electricity and other services in wholesale markets.[14]

Many states have also taken steps that promote DG. These include favorable tax treatment and other economic incentives, such as net energy metering, which is generally available for DG powered by solar energy.[15] In addition, some states have expressly sought to promote distributed generation as a way of modernizing the electricity grid. New York State is the leader of this movement in many respects. The New York State Public Service Commission's (NYPSC) Reforming the Energy Vision proceeding (REV) has sought to make DG a central component of its effort to develop a more resilient and cost-effective electricity distribution network by developing a model for compensating distributed resources, including all types of DG, for the many services that it provides to the grid.[16] REV contemplates that utilities in New York will make distributed resources, including DG, a major component of their strategy for operating and modernizing their systems—a development that could greatly increase both the number of DG units operating within the state as well as the

12 *See* NESCAUM REPORT, *supra* note 11, at 26 (discussing the increased use of internal combustion engines in demand response programs).

13 *See* FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760 (2016); Elta Kolo & Andrew Mulherkar, *SCOTUS Decision Results in $200M Impact on Demand Response in 2016*, GREENTECH MEDIA (Jan. 26, 2016), http://www.greentechmedia.com/articles/read/scotus-decision-to-make-a-200-million-impact-on-a-diversifying-dr-industry (discussing the near-term effect of the EPSA decision on demand response markets).

14 *See, e.g.*, N.Y. Indep. Sys. Operator, Inc., 155 F.E.R.C. ¶ 61,166 (2016).

15 *See, e.g.*, U.S. DEP'T OF ENERGY, NET METERING (2015), http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2015/04/Net-Metering-Policies.pdf (listing states with net energy metering).

16 *See* REV Track One Order, *supra* note 1, at 3 n.3.

amount of time that each unit operates.[17] Although no other state has proceeded as far down this path with respect to all forms of DG—as opposed to just solar-powered DG—other states have at least contemplated engaging in a similar effort to value the attributes provided by distributed resources, including DG.[18]

II. THE ENVIRONMENTAL CONSEQUENCES OF DISTRIBUTED GENERATION

To the extent that DG consists of relatively low- or non-emitting resources, such as combined-heat-and-power gas turbines or photovoltaic solar panels, it has the potential to reduce the emissions of conventional pollutants, such as NO_x and particulate matter, as well as GHGs from electricity generation.[19] In addition, because DG is located at or near the point of consumption, there is little to no loss of electricity in the transmission and distribution process, reducing the total amount of electricity that must be generated.[20] DG can also provide an alternative to building additional transmission or distribution grid infrastructure, avoiding the environmental impacts associated with these expansions.[21]

But not all DG comes from these relatively clean sources.[22] A

17 *See id.* at 2–3.

18 *See, e.g.*, Draft Regulatory Incentives Proposal for Discussion and Comment, R. 14-10-003 (Cal. Pub. Utils. Comm'n Apr. 4, 2016) (proposing reforms to how utilities are compensated for procuring distributed energy resources); Decision Adopting an Expanded Scope, a Definition, and a Goal for the Integration of Distributed Energy Resources, R. 14-10-003 (Cal. Pub. Utils. Comm'n Sept. 22, 2015) (expanding the relevant proceeding to focus on integrating and expanding the use of distributed energy resources).

19 Although CHP burns fossil fuels, it is generally significantly more efficient than the marginal—typically fossil-fuel-based—generator, meaning that, on the whole, it likely leads to a reduction in total GHG emissions. *See generally* U.S. ENVTL. PROT. AGENCY, FUEL AND CARBON DIOXIDE EMISSIONS SAVINGS CALCULATION METHODOLOGY FOR COMBINED HEAT AND POWER SYSTEMS 3–5, 9–12 (2015) (discussing means for calculating emissions GHG emissions reductions based on the use of CHP).

20 *See* N.Y. INDEP. SYS. OPERATOR, *supra* note 10, at 7. Roughly 6% of all electricity generated is due to line losses during the transmission and distribution process. *How Much Electricity Is Lost in Transmission and Distribution in the United States?*, U.S. ENERGY INFO. ADMIN. (Apr. 6, 2016), https://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3.

21 *See* Shelley Welton, *Non-Transmission Alternatives*, 39 HARV. ENVTL. L. REV. 457, 468 (2015) (discussing the potential environmental benefits of using distributed generation in lieu of building additional transmission lines).

22 "Relatively" here refers to other forms of DG. Small CHP gas turbines, while much cleaner than diesel, may nevertheless emit pollutants at a greater rate

significant component of DG consists of fossil-fuel-fired generators.[23] The mix and quantity of pollutants from fossil-fuel-fired DG varies based on the type of generator, with many forms of DG emitting levels of conventional pollutants far in excess of the per-kilowatt-hour emissions of a central generating station. In particular, diesel-fired internal combustion engines—one of the principal forms of DG in demand response programs[24]—emit large quantities of NO_x, PM, carbon monoxide (CO), and various hazardous air pollutants, including known carcinogens.[25] For example, older diesel generators can emit NO_x at rates ten times greater than that of a well-controlled coal-fired power plant.[26]

Several characteristics of fossil-fuel-fired DG can exacerbate the health and environmental impacts of its emissions. First, DG is generally located much closer to population centers than are central generating stations, which are often sited in relatively remote areas.[27] As a result, the emissions of localized pollutants from DG typically have a greater impact on human health than the same level of emissions from a central generator.

Second, fossil-fuel-fired DG units typically lack the extensive

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per-kilowatt-hour than the much larger gas turbines used in central generating stations. *See* Garvin A. Heath et al., *Quantifying the Air Pollution Exposure Consequences of Distributed Electricity Generation* 7 (Univ. of Cal. Energy Inst., Energy Policy & Econs. Working Paper, 2005) (comparing emissions rates among forms of DG with the average emissions rates of central generating stations in California).

23 *See* Envtl. Prot. Agency, *Distributed Generation of Electricity and its Environmental Impacts*, https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts#impacts (last visited Oct. 8, 2017).

24 *See* NESCAUM REPORT, *supra* note 11, at ES-1, 4–6 (discussing how federal demand response programs have incentivized increased use of distributed generation, including through the use of onsite electricity production from diesel generators).

25 *See* Sandip D. Shaha et al., *Emissions of Regulated Pollutants from In-use Diesel Back-up Generators*, 40 ATMOSPHERIC ENV'T 4199, 4199 (2006); NESCAUM REPORT, *supra* note 11, at 7 tbl.1 (listing hazardous air pollutants from reciprocating internal combustion engines); Emission Standards for Stationary Diesel Engines, 73 Fed. Reg. 4136, 4138 (Jan. 24, 2008) (to be codified at 40 C.F.R. pt. 63) (discussing "health-related concerns" regarding hazardous air pollutants from backup generators).

26 *See* NESCAUM REPORT, *supra* note 11, at ES-2.

27 *See* Tong & Zhang, *supra* note 4, at 262 (noting that diesel generators are generally located "closer to customers" and "in populated urban areas"); Heath et al., *supra* note 22, at ix (noting that "the mass of pollutant inhaled per unit electricity delivered can be up to three orders of magnitude greater for DG units," largely because of their closer proximity to population centers).

pollution controls required of central generators. In particular, smaller generators often must meet less stringent emissions standards and rarely possess the tall emissions stacks that help disperse pollutants over large areas.[28] Because emissions from DG are not dispersed as effectively as those from central generating stations, they can become concentrated in a relatively small area, creating "hotspots."[29] This concern is especially acute in urban areas, where the complex topography of buildings creates air circulation patterns that can trap pollutants, rather than dispersing them.[30] Even a relatively small increase in DG units in a particular area, or in the hours in which those units operate, could significantly increase the effect of localized pollutants on people living in the area. Policies that encourage the concentration of DG in relatively small geographic areas—which may include New York's REV proceeding—could exacerbate this effect.

Third, peak DG use is likely to occur on the hottest, most humid days when air quality is generally at its worst—even without the contribution from increased reliance on fossil-fuel-fired DG.[31] That is because the increased demand for air conditioning will typically produce high electricity prices and place a strain on the grid, creating a significant incentive to operate DG. Together, these characteristics of fossil-fuel-fired distributed generation may cause even a relatively small increase in DG utilization to result in an outsized negative effect on air quality and human health.

Finally, even relatively clean forms of fossil-fuel-fired generation (such as CHP gas turbines) emit some pollutants, including GHGs. Because GHG emissions from DG generally are not monitored, increased use of DG may result in additional GHG

28 *See, e.g.*, Qiguo Jing & Akula Venkatram, *The Relative Impacts of Distributed and Centralized Generation of Electricity on Local Air Quality in the South Coast Air Basin of California*, 39 ENERGY POL'Y 4999, 4999 (2011).

29 *See* Tong & Zhang, *supra* note 4, at 263.

30 *See id*. at 270.

31 *See* NESCAUM REPORT, *supra* note 11, at 26 ("[E]ven if diesel engines operate relatively rarely on only the highest electricity demand days, their emissions on those specific days can be relatively significant and occur at the worst possible times for air pollution."); Xiyue Zhang & K. Max Zhang, *Demand Response, Behind-the-Meter Generation and Air Quality*, 49 ENVTL. SCI. & TECH. 1260, 1265 (2014); Elisabeth A. Gilmore et al., *The Costs, Air Quality, Human Health Effects of Meeting Peak Electricity Demand with Installed Backup Generators*, 40 POL'Y ANALYSIS 6887, 6887 (2006).

emissions that go unaccounted for under efforts to cap electricity-sector emissions, such as the Clean Power Plan (CPP)[32] and the Regional Greenhouse Gas Initiative (RGGI).[33] Indeed, these programs may decrease the cost of DG relative to central generators, creating an incentive to shift generation from large central generators to smaller, distributed sources.

In general, it should be noted that there is currently a lack of information about emission levels and their effects from existing DG. These information gaps complicate the assessment of the environmental consequences of DG.

III. CURRENT REGULATION OF DISTRIBUTED GENERATION EMISSIONS

This Part presents a general overview of the basic regulatory framework applicable to fossil-fuel-fired DG. These regulations are complex, and they vary based on the type of generator and the jurisdiction in which it is located. For simplicity, this Part focuses primarily on the regulation of stationary internal combustion engines in New York State, and on diesel engines in particular. These engines are a common form of distributed generation and they emit relatively high levels of pollutants, including PM, NO_x, and SO_2, as well as GHGs. Throughout this Part, we provide examples from other jurisdictions in order to highlight the heterogeneity among approaches to regulating DG.

As discussed below, the applicable federal regulations establish emissions limits for many DG units, with larger and newer generators facing more stringent limitations. Smaller generators usually must comply only with operational standards, although newly built small engines must comply with certain emissions thresholds. State and local registration and permitting requirements follow a similar pattern. Larger engines must secure operating permits, which require them to demonstrate that they meet certain emissions standards, while smaller engines must only

32 *See* Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510 (Oct. 23, 2015) (to be codified at 40 C.F.R. pts. 60, 70, 71, 98); Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662 (Oct. 23, 2015) (to be codified at 40 C.F.R. pt. 60).

33 *See The RGGI CO_2 Cap*, REG'L GREENHOUSE GAS INITIATIVE, https://www.rggi.org/design/overview/cap (last visited Nov. 17, 2016).

register with the appropriate regulatory body, if they are required to take any action at all.

In general, these regulations are source-specific. That is, they typically address the emissions of an individual source and do not attempt to regulate aggregate emissions levels or address the effects of concentrating fossil-fuel-fired DG resources in a particular area or concentrating their operation during a particular period of time.

A. *Regulation of Conventional Pollutants*

1. *Federal Regulation*

The U.S. Environmental Protection Agency (EPA) administers the primary federal regulations for fossil-fuel-based DG. Chief among these regulations are the National Emissions Standards for Hazardous Air Pollutants (NESHAP) and New Source Performance Standards (NSPS) for stationary reciprocating internal combustion engines (RICE).[34] As noted, electric generators powered by these engines are one of the principal forms of fossil-fuel-based DG,[35] and a major participant in demand response programs.[36]

The RICE NESHAP sets generally applicable emissions-control standards for diesel and gasoline generators.[37] Under this rule, EPA imposes limits on certain hazardous emissions from new and existing diesel engines with those limits becoming progressively more stringent as the size of the engine increases (the least stringent standard applies to the covered engines with the lowest horsepower).[38] Diesel engines under 300 horsepower—

34 EPA has also issued regulations addressing other forms of small fossil-fuel-based DG, including, for example, NSPS for certain forms of gas turbines. *See* 40 C.F.R. § 60.4300 (2015).

35 *See supra* note 24 and accompanying text.

36 *See* Tong & Zhang, *supra* note 4, at 263.

37 The RICE NESHAP addresses a variety of hazardous air pollutants, including known carcinogens, such as diesel exhaust. World Health Org., Press Release, Iarc: Diesel Engine Exhaust Carcinogenic (June 22, 2012), available at https://www.iarc.fr/en/media-centre/pr/2012/pdfs/pr213_E.pdf. And although many of the emissions discussed above, including NO_x and PM, do not fall on this list, the emissions controls used to meet the NESHAP limits have the potential to also reduce the emissions of these pollutants as well. *See* 40 CFR § 63.6580 (2015).

38 *See* Compliance Requirements for Stationary Engines, U.S. ENVTL. PROT. AGENCY REGION 1, https://www.epa.gov/stationary-engines/compliance

about twice that of a 2015 diesel Volkswagen Jetta[39]—and comparably sized engines that burn gasoline generally are not subject to emissions limits.[40] Instead, they must adhere to operational "work practice" standards, such as regular oil changes and inspections, to ensure that the engine is running efficiently.[41]

In addition, EPA regulates new and significantly modified engines under the NSPS. These regulations require that engines produced after a particular point in time meet emissions standards for pollutants including NO_x, PM, and CO, with those standards varying based on the size and other characteristics of the engine, including whether it runs on gasoline or diesel fuel.[42] EPA has implemented these standards in time-specific "tiers," with each tier applying progressively more stringent emissions limitations to engines built after the tier goes into effect.[43] These tiers, however, are not retroactive. That is, the NSPS generally do not require an engine that was completed before a particular tier goes into effect to comply with a subsequent, more stringent tier.[44]

requirements-stationary-engines (last visited Oct. 8, 2017). For example, a diesel engine with more than 300 horsepower cannot emit more than 49 parts per million of carbon monoxide while one larger than 500 horsepower cannot emit more than 23 parts per million. *See id*. Alternatively, an engine's operator can comply by installing controls that create a more than 70% reduction in CO emissions. *See id.* Although the NESHAP sets limits for multiple hazardous pollutants, CO emissions are used for compliance purposes because the level of CO emissions is, based on the control methods generally used, a good proxy for emissions of the relevant hazardous pollutants. *See id*. EPA's limits on smaller diesel engines are more stringent if the engine is located at a facility that is a major source of hazardous pollutants—that is, if it has the potential to emit more than 10 tons per year of any pollutant or more than 25 tons of all pollutants designated as hazardous. *See id.*

39 *See 2015 Volkswagen Jetta Diesel: Features & Specs*, EDMUNDS, http://www.edmunds.com/volkswagen/jetta/2015/diesel/features-specs/ (last visited Nov. 17, 2016) (listing the characteristics of 2015 diesel Jetta).

40 *See* Melanie King, *EPA's Air Quality Regulations for Stationary Engines*, ENVTL. PROT. AGENCY 18–20 (May 2, 2013), https://www.epa.gov/sites/production/files/2014-03/documents/6_2012_webinaroverview_rice.pdf.

41 *Id.*

42 *See id.* at 24, 32 (describing different standards applicable to spark and compression engines); Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 C.F.R. § 60.4200 (2015).

43 Generally, operators demonstrate compliance with the NSPS by purchasing a qualifying engine and operating it consistently with the manufacturer's guidelines. Only relatively large engines—*i.e.*, those in excess of 30 liters per cylinder—must undergo regular emissions testing. *See* 40 CFR § 60.4211; King, *supra* note 40, at 23–24.

44 *See* 40 CFR § 60.4211; King, *supra* note 40, at 23–24.

In 2013, EPA significantly expanded an exemption from the RICE NESHAP and NSPS in order to make it easier for DG to participate in demand response programs without incurring potentially insurmountable emissions-control costs.[45] The exemption applied to engines that operate for fewer than 100 hours per year and only for certain purposes, such as regular maintenance or reliability-based demand response.[46] In addition, the rule provided that up to 50 of the 100 hours could be in non-emergency conditions if the owner did not receive financial compensation in exchange for running the engine or if any financial compensation was pursuant to an agreement with a local distribution grid operator for the purposes of ensuring reliability.[47]

In 2015, the D.C. Circuit Court of Appeals invalidated this exemption. The court concluded that EPA failed to adequately respond to concerns about the effects of the 100-hour exemption.[48] Although EPA successfully sought a stay of the court's mandate, it elected not to promulgate new regulations and, as a result, engines that support demand response generally do not qualify as "emergency" engines and must meet the emission standards described above.[49]

In addition, many of the emissions from fossil-fuel-based DG are "criteria" pollutants subject to EPA regulation under the National Ambient Air Quality Standards (NAAQS).[50] States are primarily responsible for bringing into compliance areas where

45 *See* National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, 78 Fed. Reg. 6674, 6679 (Jan. 30, 2013) (to be codified at 40 C.F.R. pts. 60, 63) ("The EPA believes that the emergency demand response programs that exist across the country are important programs that protect the reliability and stability of the national electric service grid. The use of stationary emergency engines as part of emergency demand response programs can help prevent grid failure or blackouts, by allowing these engines to be used for limited hours in specific circumstances of grid instability prior to the occurrence of blackouts.").

46 *See id*.

47 *See id.*

48 *See* Del. Dep't of Nat. Res. & Envtl. Control v. EPA, 785 F.3d 1, 18 (D.C. Cir. 2015).

49 *See* U.S. ENVTL. PROT. AGENCY, GUIDANCE ON VACATUR OF RICE NESHAP AND NSPS PROVISIONS FOR EMERGENCY ENGINES (2016), https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516. pdf.

50 *See NAAQS Table*, U.S. ENVTL. PROT. AGENCY, https://www.epa.gov/criteria-air-pollutants/naaqs-table (last visited Nov. 17, 2016).

pollution exceeds the NAAQS, as parts of New York do for ozone and certain forms of particulate matter (primarily New York City and the surrounding counties).[51]

2. *State Environmental Protection Agencies*

a. *New York State Department of Environmental Conservation*

New York State's primary regulation of smaller generators occurs through a registration and permitting regime administered by the New York State Department of Environmental Conservation (NYSDEC). As a general matter, New York State has established permitting requirements for significant emissions sources. Significant sources covered by these requirements include sources that emit 50 percent or more of the threshold for qualifying as a "major source" under Title V of the Clean Air Act.[52] This level of emissions, however, is above what most individual DG resources are likely to emit.

Instead, it is more likely that DG will participate in New York's minor facility registration program, which applies to sources too small to require a permit, unless those sources qualify as exempt or trivial.[53] The registration requirements include a list of all state and federal limits applicable to the source[54]—for example, the NSPS and NESHAP regulations discussed in the previous section. Many smaller fossil-fuel-fired generators may qualify as exempt generators, which excuses them from the registration requirement, although larger ones will be required to participate in the minor source registration program.

NYSDEC has recently enacted new regulations to address emissions from fossil-fuel-fired DG. These regulations, known as

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51 *See Current Nonattainment Counties for All Criteria Pollutants*, U.S. ENVTL. PROT. AGENCY (Sep. 22, 2016), http://www3.epa.gov/airquality/greenbook/ancl.html (listing non-attainment counties).

52 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 201-5.1 (2013) (describing the applicability of state permit requirements); N.Y. COMP. CODES R. & REGS. tit. 6, § 201-6.1 (2013) (describing the applicability of the Title V permit requirements).

53 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 201-4.1 (2013). Exempt or trivial sources include small liquid or gaseous fueled generators—i.e., those under 200 horsepower in the greater New York City metropolitan area and certain parts of Orange County and those under 400 horsepower in the rest of the state. N.Y. COMP. CODES R. & REGS. tit. 6, § 201-3.2. The operators of these sources must maintain records demonstrating that they qualify as exempt or trivial. *Id.*

54 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 201-4.3 (2013).

Part 222, establish emissions limits for a range of pollutants from relatively large distributed generation—as the NYSDEC puts it, these regulations generally apply to DG in commercial and institutional settings, but not to those units in residential ones.[55] The new regulations are intended, at least in part, to address the effects of REV on demand for and operation of distributed energy resources.[56] Part 222 applies to all eligible units, except those that operate only in emergency conditions—i.e., when electricity is not available from the grid.[57] In this respect, it is similar in design to the federal regulation under the NSPS and NESHAP regulations, but Part 222 applies to already-installed units unlike the NSPS.[58]

Part 222 also includes some novel regulatory approaches. For example, it contemplates that many owners of diesel-fired DG will convert their generators to natural gas, and it provides a one-year extension of the compliance deadline for those that intend to do so.[59] It also provides a one-year extension for owners that intend to shut down their DG units rather than comply with the new emissions limits.[60] Although an estimate of the combined effect of these incentives is outside the scope of this Article, these one-year extensions should provide an incentive to improve or remove relatively dirty DG, although perhaps at a near-term cost of slightly greater emissions.

b. *Other State Models*

A number of other states have developed different approaches for addressing emissions from DG. This Section discusses some of the leading examples, and notes instances in which they differ from the New York regulations discussed in the previous section. Perhaps the most aggressive such program has been California's, in which the California Air Resources Board (CARB) promulgated a series of stringent regulations applicable to all new and existing diesel generators greater than 50 horsepower.[61] These include

55 *See Fact Sheet Part – 222*, N. Y. STATE DEP'T OF ENVTL. CONSERVATION, http://www.dec.ny.gov/regulations/104280.html (last visited Nov. 17, 2016).

56 *See id*.

57 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 200.1 (2016).

58 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 222.1(a) (2016).

59 *See* N.Y. COMP. CODES R. & REGS. tit. 6, §§ 222.2(b)(2), 222.5(d).

60 *See id*.

61 *See* CAL. CODE REGS. tit. 17, §§ 93115.6 (establishing emissions standards for emergency generators), 93115.7 (establishing emissions standards for prime generators), 93115.9 (describing emissions limitations for generators

emissions limits for PM, CO, non-methane hydrocarbon (NMHC), and NO_x, with more lenient standards for engines that operate only during emergencies.[62] In addition, California limits emissions of these same pollutants from smaller engines—i.e., those under 50 horsepower—but only if they were installed after 2005.[63] California allows local government agencies—local pollution control districts or air quality management districts—to take an even more aggressive approach by establishing more stringent limits for any or all of these pollutants.[64] In short, California provides one of the closest parallels to New York's Part 222 environmental regulations, although it is more comprehensive because it applies to all generators within the state, including smaller generators and generators used only during emergencies.

Most other states that address emissions from DG do so through a series of emissions limits on some or all types of DG. These state regulations, however, exhibit a number of other notable differences from New York and California. Delaware, for example, establishes emissions limits applicable to most DG with the specific limits varying based on the unit's fuel type and installation date.[65] As discussed further below, Delaware also limits CO_2 emissions[66] and establishes restrictions on when DG

installed after 2005 and stricter limitations for generators installed after 2011).

62 The exact emissions limit for each pollutant varies based on a generator's date of installation and horsepower. For newer prime generators of higher horsepower, there are separate NO_x and NMHC limits. For emergency generators and older or lower horsepower prime generators, there is a single cap for combined NO_x and NMHC emissions. *See supra* note 61.

63 *See* CAL. CODE REGS. tit. 17, § 93115.9 (describing emissions limitations for generators installed after 2005 and stricter limitations for generators installed after 2011). Portable diesel generators greater than 50 horsepower are subject to PM limits. *See* CAL. CODE REGS. tit. 17, § 93116.3(b) (2016).

64 *See* CAL. CODE REGS. tit. 17, §§ 93115.7(a)(5) (stating that districts can create stricter cite-specific emissions limitations for prime generators), 93115.6(a)(3)(B) (stating that districts can create stricter emissions limitations for emergency generators); CAL. CODE REGS. tit. 17, § 93115.7(a)(4) (2016) (stating that districts can create "additional emissions limitations" for prime generators operated for the purpose of DG).

65 *See* 7 DEL. ADMIN. CODE § 1144-3 (2006). The exceptions to this rule include generators with a standby capacity of less than 10 KW, generators serving a residential property for three or fewer families, mobile generators, and "a generator covered by a permit which imposes a NO_x emission limitation established to meet Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER)." 7 DEL. ADMIN. Code § 1144-1.2.1.1 (2006).

66 *See* 7 DEL. ADMIN. CODE § 1144-3.2.1.1 (2006).

can operate for certain purposes—prohibiting DG from operating for testing or maintenance before 5:00 p.m. when the state is experiencing high levels of ozone or particulate pollution.[67]

New Jersey bans the operation of certain generators for testing and maintenance on days designated by the state's Department of Environmental Conservation as having poor air quality.[68] In addition, New Jersey creates incentives for achieving low emissions rates of pollutants that are not subject to a mandatory emissions limit. That is, although any non-emergency generator greater than 37kW also counts as "a significant source (and, therefore, requires a preconstruction permit and an operating certificate) . . . ."[69] New Jersey will waive this requirement for generators under 500 kW if they can show that their per-megawatt-hour emissions of NO_x, CO, PM, and SO_2 are below specified levels, even though the only binding emissions limits for DG in the state are for NO_x.[70]

In Massachusetts, non-emergency generators with a capacity greater than 50kW are subject to NO_x, PM, CO, and CO_2 emissions limits.[71] But as an alternative to complying with these emissions requirements, the operator of certain DG units can use a streamlined process[72] under which a source will be approved if it is shown to comply with the most stringent of a set of federal emissions standards.[73]

3. *State Public Utility Commission Regulation*

In New York, the New York Public Service Commission has enacted regulations addressing DG on a case-by-case basis. Whereas the NYSDEC regulations focused on the emissions levels of a particular generator, the NYPSC has focused on limiting the amount of demand response that the grid operator can take from certain types of fossil-fuel-based DG. For example, in approving

67 *See* 7 DEL. ADMIN. CODE § 1144-4.4 (2006).

68 *See* N.J. ADMIN. CODE § 7:27-19.2(d) (2016).

69 N.J. ADMIN. CODE § 7:27-8.2(c) (2016).

70 *See* N.J. ADMIN. CODE § 7:27-8.2(f) (2016).

71 *See* 310 MASS. CODE REGS. 7.26(43)(b) (2016).

72 *See* 310 MASS. CODE REGS. 7.26(43)(a) (2016).

73 The federal standards include LAER, BACT, NSPS, NESHAP, and Maximum Achievable Control Technology (MACT). *See* 310 MASS. CODE REGS. § 7.02(8) (2016). This program is applicable to a generator that is "a peaking power production unit, load shaving unit [or] a unit in an energy assistance program." 310 MASS. CODE REGS. § 7.26(43)(a) (2016).

Consolidated Edison's (Con Edison) demand response program in New York City in 2009, the NYPSC established three restrictions to address environmental justice concerns associated with diesel generators. First, it prohibited non-renewable fossil-fuel generators located within half a mile of certain gas turbines in the city from participating in the program.[74] Second, it capped diesel generators' participation in the program at 20 percent of the total megawatt enrollment.[75] Third, it limited the participation of diesel and certain natural gas engines to model year 2000 and newer engines.[76] The NYPSC incorporated these same limitations into Con Edison's more recent Brooklyn Queens Demand Management program (BQDM program),[77] in which Con Edison is seeking to use demand-side resources to help defer or avoid the need to build a new distribution substation.[78]

Once again, California provides an interesting counterpoint to the initiatives in New York. In 2013, as part of a major proceeding on demand response, the California Public Utilities Commission (CPUC) considered instituting an outright ban on fossil-fuel-fired DG in demand response programs within the state.[79] Although the CPUC believed that it possessed jurisdiction to institute such a ban, it stopped short of doing so, instead requiring utilities to begin collecting information on the utilization of fossil-fuel-fired backup generators as part of demand response programs.[80] That

74 *See* Order Adopting in Part and Modifying in Part Con Edison's Proposed Demand Response Programs, Case No. 09-E-0115 (N.Y. Pub. Serv. Comm'n Oct. 23, 2009) [hereinafter Order Establishing Con Edison Demand Response Program].

75 *See id.* at 21.

76 *See id.* Con Edison's most recent update on demand response programs to the NYPSC also states that it limits participating generators based on model year, emissions-control technology, or NOx emissions rate. *See* Consolidated Edison Company of New York, Inc. Report on Program Performance and Cost Effectiveness of Demand Response Programs at 18, Case No. 09-00115 (N.Y. Pub. Serv. Comm'n Dec. 1, 2014).

77 *See* Order Establishing Brooklyn/Queens Demand Management Program at 17, Case No. 14-E-0302 (N.Y. Pub. Serv. Comm'n Dec. 12, 2014) [hereinafter Order Establishing BQDM Program].

78 *See id.* at 2–3.

79 *See* Decision Resolving Several Phase Two Issues and Addressing the Motion for Adoption of Settlement Agreement on Phase Three Issues at 51–52, Case No. R. 13-09-011 (Cal. Pub. Utils. Comm'n Sept. 19, 2013), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K552/143552239.pdf.

80 *See id.* at 60–61. The CPUC also expressed its belief that it possessed the jurisdiction to ban all fossil-fuel-fired backup generators from participating in

information was submitted in November 2015, but the CPUC has yet to decide whether to permit these fossil-fuel-fired generators to participate in demand response going forward.

In addition, California's major investor-owned utilities recently completed their first auction, known as the Demand Response Auction Mechanism (DRAM), to procure grid-scale distributed resources.[81] As with New York's BQDM project, the purpose of this auction is, at least in part, to use distributed resources to forestall the need for additional grid upgrades or generation. DG is one of the principal resources available to meet that goal. In setting its final rules for the auction, however, the CPUC established a complete ban on fossil-fuel-fired backup generators, after concluding that they were inconsistent with the state's environmental goals.[82] In essence, California has taken the ban that New York applied to fossil-fuel-fired DG operating near a power plant and extended it to the entire state, at least for the DRAM. The CPUC also indicated that it would use the DRAM experience as evidence when deciding whether to expand the ban on fossil-fuel-fired backup generators to its larger demand response program, discussed above.[83] The CPUC's approach to DG is thus similar to the NYPSC's, although it may ultimately go much further by barring the participation of certain classes of fossil-fuel-fired DG throughout the state—something that New York does not appear to have contemplated to date.

4. *Local Regulation*

The New York City Department of Environmental Protection (NYCDEP), which promulgates its own environmental

demand response within the state, not just those administered by a utility. *See id.* at 57–58.

81 *See* Resolution E-4728 (Cal. Pub. Utils. Comm'n July 23, 2015), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K436/153436367.pdf.

82 *See id.* at 14.

83 *See id.* at 15 ("Disallowing fossil-fueled BUGs [backup generators] in this pilot program could provide additional insight for the Commission when it decides the overall policy on fossil-fueled BUGs."). A recent proposed decision adopted the position that the state should expand this ban on most forms of fossil-fuel backed DG throughout the CPUC's demand response programs. *See* Decision Adopting Guidance for Future Demand Response Portfolios and Modifying Decision 14-12-024, at 2, Case No. R. 13-09-011 (Cal. Pub. Utils. Comm'n Aug. 30, 2016), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M166/K460/166460832.PDF.

requirements under the New York City Air Code, is the leading local regulator for DG within New York. As with the federal and state regulations, the NYCDEP regulations increase in stringency with the size of the generator. Relatively large generators—those with maximum input in excess of 4.2 million British Thermal Units (BTUs), depending on their fuel type—are required to register with the city and obtain an operating permit for the engine.[84] Notably, the City's recent amendments to its Air Code will soon utilize EPA's forward-looking NSPS requirements as a baseline for retrofits. Beginning in 2025, the city will no longer renew operating permits for diesel generators unless those generators meet EPA's Tier 4 emission standards, even though the EPA makes the Tier 4 standards applicable only to new engines.[85]

Smaller engines are not required to obtain operating permits. Engines below the 4.2-million-BTU thresholds need only register with the City, and very small engines—those with a maximum input less than 350,000 BTUs—are neither required to register nor to obtain an operating permit.[86] In addition, engines that are used only in emergency circumstances are not required to obtain an operating permit, regardless of size, although they must be registered with NYCDEP.[87] Unlike EPA's emergency generator exception, however, New York City limits emergency generators to operating only when their facility cannot receive power from the grid.[88] That is, in order to qualify as an emergency generator under the New York City code, a source cannot participate in peak shaving or even reliability-based demand response.[89]

The City of Chicago also relies primarily on a permitting approach for addressing emissions from DG. It requires that individuals obtain a permit in order to "install . . . operate . . . replace or relocate"[90] equipment, including "combustion equipment" such as fossil-fuel-fired DG.[91] A permit is also

84 *See* N.Y.C. ADMIN. CODE § 24-109 (2017).

85 *See* N.Y.C. ADMIN. CODE § 24-149.6(b) (2016) (citing the tier 4 requirement).

86 *See id.*

87 *See* N.Y.C. ADMIN. CODE §§ 24-104, -109, -122(c) (2016).

88 *See* § 24-109 (defining an emergency generator as "an internal combustion engine that operates as a mechanical or electrical power source only when the usual source of power is unavailable.").

89 *See id.*

90 CHI., ILL., MUN. CODE tit. 11, § 11-4-620 (2016).

91 The § 11-4-620 permitting requirements apply to, among other equipment,

required in order to "repair or modify" the equipment in a way that would "increase the quantity or change the nature of air contaminants emitted."[92] Guidance from the City indicates that the permitting requirement applies even to equipment that generates very small amounts of pollution.[93] The City will grant a permit only if the "control equipment or technology to be utilized to control the emission of air contaminants is appropriate for the facility's operations and throughput."[94] Control technology permitted by state or federal law will be considered appropriate.[95]

San Francisco, by contrast, establishes more affirmative limitations on fossil-fuel-fired DG under its jurisdiction. It requires annual renewals of certificates of operation for diesel backup generators greater than 50 horsepower.[96] In addition, these generators are limited to 50 hours of non-emergency operation per year, must have "best available control technology" (as determined by either the California Air Resource Board or the Bay Area Air Quality Management District) installed, and must be fitted with a meter that measures fuel use or hours of operation.[97]

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In summary, fossil-fuel-fired DG is generally subject to a suite of federal, state, and, in some cases, local regulations. These regulations are largely source-specific. Although they regulate

"'[c]ombustion equipment' [which] means any equipment or device which generates heat or energy by burning solid, liquid, or gaseous fuel or other material, and which emits or has the potential to emit air contaminants"—a category that specifically includes "generators." CHI., ILL., MUN. CODE tit. 11, § 11-4-610 (2016).

92 § 11-4-620.

93 A guide on the City of Chicago's website indicates that "[n]either the size of the facility nor the amount of the air contaminant has any bearing on whether or not you need a permit." CITY OF CHI. DEP'T OF ENV'T, A GUIDE TO OBTAINING AIR POLLUTION CONTROL PERMITS 3 (2011), http://www.cityofchicago.org/content/dam/city/depts/doe/general/PermittingAndEnforcement_PDFs/AirQualityPermits/AirPollutionControlGuidev3.pdf.

94 CHI., ILL., MUN. CODE tit. 11, § 11-4-630 (2016).

95 The municipal code contains a provision stating that "any control equipment or technology permitted by state or federal law or regulation shall be considered appropriate," *id.*, but the definition of "air pollution," CHI., ILL. MUN. CODE tit. 11, § 11-4-610, is broad enough to potentially sweep in pollutants for which there is no state or federal standard.

96 *See* S.F., CAL., HEALTH CODE, art. 30, §§ 2003 (requiring certificates for both new and existing diesel backup generators), 2002(d) (defining "diesel backup generator" to include only generators greater than 50 horsepower), 2008 (indicating that a certificate is valid for one year) (2016).

97 S.F., CAL., HEALTH CODE, art. 30, § 2006 (2016).

emissions for certain types of DG, which reduces the overall emissions potential of DG sources, they generally do not address concerns about geographic or temporal concentration of DG emissions. The principal exception to this rule is the set of restrictions that the NYPSC has implemented with respect to Con Edison's demand response programs.[98] In addition, some of the most stringent regulations, EPA's NSPS, are only forward-looking. As a result, the current NSPS limits do not apply to the large percentage of engines that were installed pursuant to previous, more lenient NSPS rules.[99] Many relatively small sources of DG are exempted from emissions monitoring entirely. Although these smaller DG units may operate less frequently (and produce lower total emissions) than larger units, a sufficient concentration could nevertheless lead to significant adverse health impacts. Emergency generators may also receive relaxed treatment, such as less stringent emissions standards.[100]

B. *Regulation of GHGs*

Efforts to regulate GHG emissions from the power sector—on both the state and federal level—overwhelmingly focus on sources with a capacity of 25 Megawatts (MW) or more. To the extent that these efforts, such as the EPA's Clean Power Plan (CPP)[101] or the Northeast's Regional Greenhouse Gas Initiative (RGGI),[102] increase the cost of operating larger sources without imposing similar costs on small sources, they will make DG into a cheaper means of generating electricity. A shift of generation from centralized stations to relatively inefficient fossil-fuel-fired DG could erode the emission-reduction benefits of GHG policies. Such "leakage" would be most problematic if the incremental generation

98 *See* Order Establishing BQDM Program, *supra* note 77, at 17; Order Establishing Con Edison Demand Response Program, *supra* note 74, at 20–21.

99 *See* Tong & Zhang, *supra* note 4, at 263 ("[A] large percentage of diesel backup generators that are in use are Tier 1, Tier 2 or older, which have considerably higher emission rates than those of the latest models.").

100 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 222.1(b) (2016).

101 *See* Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510 (Oct. 23, 2015) (to be codified at 40 C.F.R. pts. 60, 70, 71, 98); Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662 (Oct. 23, 2015) (to be codified at 40 C.F.R. pt. 60).

102 *See The RGGI CO_2 Cap*, *supra* note 33.

was supplied by diesel generators, which, in addition to GHGs, also emit significant levels of black carbon—a form of PM that is a potent heat-trapping compound.[103] As explained below, under the CPP, states can deploy the regulatory tools at their disposal—which are discussed at the end of this paper—to mitigate any increases in GHG emissions from DG.

1. *Federal Regulation*

EPA's Clean Power Plan is, at the time of writing, the primary federal regulation of GHG emissions from electric generating units.[104] The Clean Power Plan, however, applies only to sources with a generation capacity greater than 25 MW—far in excess of the vast majority of DG units.[105] States may comply with the CPP by enacting either rate- or mass-based limits on their GHG emissions.[106] Although the CPP requires states to address the issue of generation shifts to new, relatively large sources, and provides presumptively acceptable means of doing so,[107] it leaves the

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103 *See Basic Information: Black Carbon*, U.S. ENVTL. PROT. AGENCY, https://www3.epa.gov/airquality/blackcarbon/basic.html#where (last visited Mar. 10, 2017).

104 *See* Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510; Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662. Needless to say, the election of President Donald Trump has cast serious doubt on the CPP's fate. However, the CPP remains in effect for the time being and this Article will treat the regulation accordingly.

105 *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, 64,715–16.

106 *See id.* at 64,664.

107 *See id.* at 64,888 (stating that states can regulate additional sources if they choose).

The options for a mass-based program are as follows. First, a state may enact an overall cap on GHG emissions that includes an allowance both for large existing sources subject to Section 111(d) and for large new sources subject to Section 111(b). *See id.* at 64,888–89. An overall cap reduces the incentive to shift generation between sources subject to Sections 111(b) and 111(d). As the final rule observes, this model is similar to RGGI and there is thus every reason to believe that New York will elect this method of compliance. *See id.* at 64,888.

Second, a state may carve out a portion of its mass-based limit to create a pair of allowances that would counteract the incentive to shift generation to new sources subject to Section 111(b). The first allowance would go to existing sources regulated under Section 111(d) based on the amount they generate, giving an incentive for them to run rather than shifting production to Section 111(b) units. In so doing, the allowance gives the mass-based limit a rate-like quality. *See id.* at 64,889–90. A second allowance would be for renewable

question of whether to address shifts to smaller generators entirely to the states.[108] Absent effective state action, there is a risk that either a rate- or mass-based approach could encourage shifts in electricity production from large power plants, which are subject to the mass-based cap or included in the calculations of emissions rates, to sources that fall under the 25 MW threshold and are outside the scope of the CPP.

2. *State Regulation*

New York regulates carbon dioxide emissions as part of RGGI.[109] New York's regulations implementing RGGI, however, exempt sources smaller than 25 MW from reporting and compliance requirements.[110] As most DG falls well below that threshold, it appears that RGGI would not directly address the issue of GHG leakage to small fossil-fuel-based generators.

Some states have established source-specific CO_2 emissions limits for fossil fuel generators, although, unlike RGGI, they do not cap the total amount of CO_2 that may be emitted from DG. Delaware,[111] Rhode Island,[112] and Massachusetts[113] all set a CO_2 emissions limit of 1,650 lbs./Megawatt-hour (MWh) for non-emergency generators installed on or after January 1, 2012. Additionally, Rhode Island limits CO_2 from emergency generators to 1,900 lbs/MWh.[114] California does not have source-specific standards for GHG emissions from DG, but may capture some of

energy, creating an incentive to shift production to renewable sources rather than to sources regulated under 111(b). *See id.*

Finally, a state may address the leakage concern by providing EPA with credible analysis that, based on other state regulations or the particular characteristics of that state, leakage is not a significant concern. *See id.* at 64,890. EPA has provided little guidance on what will suffice to make this showing.

108 *See id.* at 64,888.

109 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 242-1.4(a) (2015).

110 *See id.*

111 In addition to this standard for new generators, Delaware limits CO_2 emissions from existing non-emergency generators to 1,900 lbs/MWh. *See* 7 DEL. ADMIN. CODE § 1144-3 (2015).

112 Generators installed between May 15, 2007, and December 31, 2011 are limited to CO_2 emissions of 1,900 lbs/MWh. *See* 12-031 R.I. CODE R. § 43.4 (LexisNexis 2016).

113 Generators installed between March 23, 2006 and December 31, 2011 are limited to CO_2 emissions of 1,900 lbs/MWh. *See* 310 MASS. CODE REGS. 7.26 (2016).

114 *See* 12-031 R.I. CODE R. § 43.4.

these emissions through the state's cap-and-trade program. Starting in 2015, fuel suppliers—including suppliers of gasoline and diesel fuels[115]—are required to obtain trading permits if the amount of fuel they sell or import in California would produce 25,000 metric tons or more of CO_2 equivalent per year.[116] The emissions from DG that runs on fuel purchased from one of these suppliers would therefore be covered by California's emissions cap, which imposes a price on these emissions.

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In general, most states do not address GHGs from DG, although the CPP raises the possibility that states could begin regulating these emissions in order to avoid "leakage" to sources below 25 MW.

IV. POLICY OPTIONS

This Part outlines a variety of potential policy approaches for reducing the emissions from fossil-fuel-fired DG. It does not, however advocate for a particular approach. Whether one or more of these approaches makes sense is a question that will depend heavily on the characteristics of a particular jurisdiction (state, city, or other local government). For example, jurisdictions should determine whether any human health impacts from increased DG would be felt throughout the state or municipality, or only felt in a handful of relatively small areas. That determination will be important for assessing whether it would be more cost-effective to pursue broadly applicable emissions limits or, instead, a program intended to eliminate a few specific hotspots. Similarly, jurisdictions should assess the causes for increased fossil-fuel-fired DG. These factors are important to analyzing whether it is more effective to address the effects of fossil-fuel-fired DG through individual programs, such as the NYPSC's approach to demand response, or broadly applicable measures, such as NYSDEC's Part 222.

The purpose of this Part is to outline a number of different approaches that jurisdictions might consider as they evaluate these

115 *See* CAL. CODE REGS. tit. 17, § 95811(d) (2016); *Information for Entities that Take Delivery of Fuel for Fuels Phased into the Cap-and-Trade Program Beginning on January 1, 2015*, CAL. AIR RES. BOARD, https://www.arb.ca.gov/cc/capandtrade/guidance/faq_fuel_purchasers.pdf (last visited Oct. 8, 2017).

116 *See* CAL. CODE REGS. tit. 17, § 95812(d) (2016).

local considerations. In doing so, it focuses overwhelmingly on options available within New York. Several factors in New York State, including the REV proceeding and the high electricity prices experienced in New York City and Long Island, may promote increased DG. As a result, many of these policies could be relevant as New York State responds to the possible effects of this increase.

All of the options discussed below would benefit from better information regarding the number, type, location, and hours of operation of fossil-fuel-fired DG units already in use—i.e., the sort of information that California has ordered its utilities to compile as part of the demand response programs.[117] In the case of New York, some (but not all) of this information could likely be compiled from the registration and permitting requirements administered by the NYSDEC and NYCDEP. Nevertheless, additional efforts to identify and monitor the emissions from fossil-fuel-fired DG are important in order to assess their environmental and human-health impacts. Efforts to develop this information will help to identify both the magnitude of the potential health and environmental impacts of increased DG emissions and what steps can cost-effectively be deployed to address these emissions.

A. *Options for Addressing Conventional Pollutants*

There are two general approaches to regulating DG emissions of conventional pollutants. First, regulators may limit the emissions from any particular source. This source-specific approach is, by and large, the approach embodied in the current suite of environmental regulations described above in Part III. Second, regulators may attempt to reduce or limit the aggregate level of conventional pollutants in a particular area, including emissions from DG. The following subsections describe a number of ways in which regulators might deploy these approaches to address concerns about increased emissions from DG.

1. *Source-Specific Standards*

Source-specific standards set a generally applicable rule—or series of rules—for every source in a particular category. Thus, all else equal, they reduce the total emissions from fossil-fuel-fired DG, which in turn reduces the likelihood that emissions from DG will reach harmful levels in any particular area. One of the primary

117 *See supra* note 79 and accompanying text.

virtues of the source-specific approach is its administrative simplicity. Because these rules apply to an entire category of units, it is relatively straightforward to determine whether a source is in compliance with these limits. Examples of this approach include the EPA regulations discussed above as well as the regulations imposed by California, Delaware, New Jersey, and Massachusetts.[118] New York State's new Part 222 regulations, as noted, establish source-specific emissions standards for certain forms of DG.[119]

In addition, given the especially serious concerns associated with diesel generators—as opposed to relatively clean sources of fossil-fuel-fired DG[120] such as natural gas-fired CHP—regulators might also consider imposing significantly stronger emissions thresholds on diesel generators in particular. As noted, NYCDEP has taken action along these lines by requiring, beginning in 2025, that diesel generators meet EPA's NSPS Tier 4 standards in order to renew an operating permit.[121] New York State's Part 222 regulations also incorporate this principle through, for example, providing an extension of the compliance date if a generator switches from diesel to natural gas.[122] Strengthening the regulation of a particularly dirty class of generators, such as diesel-fired DG, may reduce emissions in multiple ways. For example, more stringent emissions limits on diesel-fired DG would not only reduce the emissions from the covered units, but would also create an incentive to shift investment toward other forms of DG, which will almost certainly prove cleaner than the displaced diesel-fired units.

Source-specific regulations, however, are generally not well tailored to the problem of hotspots. Although reducing emissions from particular DG units will reduce the likelihood that a hotspot will develop, it does not guarantee it. If enough DG units—even relatively well-controlled units—are installed in a particular area or operated at a particular time, they may still cause a hotspot, especially if the area is experiencing elevated background levels of the relevant pollutants—e.g., if it is downwind from a central

118 *See supra* Section III.A.

119 *See* N.Y. COMP. CODES R. & REGS. tit. 6, §§ 222.2(b)(2), 222.4 (2016).

120 Once again, "relatively" refers other forms of DG. *See supra* note 22.

121 *See* N.Y.C. ADMIN. CODE § 24-149.6(b) (2016).

122 *See* N.Y. COMP. CODES R. & REGS. tit. 6, §§ 222.3(a)(1), 222.5(e)(1) (2016).

generating station.[123]

2. *Aggregate Emissions-Level Regulation*

Approaches aimed at reducing or limiting the aggregate level emissions within a certain geographic area or time period may prove more effective at limiting hotspots, but they may prove harder and costlier to administer. This section outlines a few possible approaches by which regulators might attempt to regulate the aggregate emissions of DG in a particular area, beginning with options available to environmental regulators before turning to those available to electricity regulators. This is another area that would benefit considerably from better information, including information regarding where and with what frequency hotspots appear.

3. *Potential Environmental Regulation Approaches*

Environmental regulation offers a number of approaches for addressing an increase in DG emissions. One option is to establish a cap on emissions of conventional pollutants applicable to all sources that contribute to a particular hotspot—*i.e.*, including both centralized generators and DG units. Sources covered by the cap then could be allocated tradable permits to emit that add up to the cap. The principal advantage of using a cap-and-trade program would be to let the relevant sources determine among themselves the cheapest way of reducing emissions to an acceptable level, which helps to ensure that the necessary emissions reductions are taken by the entities with the lowest cost to reduce, it provides an economically efficient means of reducing pollutant concentrations. The downside of this approach, however, is that developing and enforcing these hotspot-level caps could prove complicated and administratively costly. Accordingly, the efficiency gains from this approach would likely have to be significant in order to justify these costs.

Another approach, which would likely have lower administrative costs, is to enact more stringent source-specific regulations for sources at or near a hotspot. For example, NYSDEC could tighten the emissions limits for all sources within a certain distance of an identified hotspot. There is already some precedent for this in New York State: as noted, it is more difficult

123 *See* Tong & Zhang, *supra* note 4, at 263.

to qualify as an exempt or trivial generator under the NYSDEC registration requirements in the greater New York City area and parts of Orange County than in the rest of the state.[124] And the Part 222 regulations enacted by the NYSDEC also adopt this approach by making it more difficult to qualify as an exempt generator in certain densely populated areas.[125] Regulators might consider making it even more difficult—or impossible—to qualify as exempt generator in an area where emissions could cause or contribute to a hotspot. In addition, regulators might also employ additional measures to reduce the aggregate emissions of fossil-fuel-fired DG units, such as limiting the number of hours that units can operate near a hotspot or banning their use outright, at least during hot and humid days, when air quality is likely to be at its worst. Delaware and New Jersey, as discussed above, utilize this approach in restricting the operation of at least some units during days of poor air quality.[126]

4. *Potential Electricity-Regulation Approaches*

Electricity-sector regulation also presents several options for addressing emissions from DG. The electricity sector relies on several markets or market-like mechanisms that can incentivize DG. These include demand response programs at both the wholesale and retail levels, as well as demand-side management programs such as Con Edison's BQDM project and California's DRAM, and, potentially, time-variant pricing. Eventually, these market mechanisms may encompass other programs that seek to procure energy services more generally, including the Distributed Service Platforms (DSP) envisioned in the REV proceeding.[127]

Because market mechanisms are an important reason for the growth of DG, regulating these markets directly can provide a straightforward means of addressing DG emissions. Such regulation is likely to prove especially desirable when particular programs cause or contribute to a significant number of the hotspots in a particular state. This sort of market regulation can take several forms. As noted, the NYPSC has established a

124 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 201-3.2 (2016).

125 *See* N.Y. COMP. CODES R. & REGS. tit. 6, § 222.1 (2016).

126 *See supra* notes 65–70 and accompanying text.

127 *See* REV Track One Order, *supra* note 1, at 11. The REV envisions that the DSP will operate a market for a variety of services, although not, at the time being, for the purchase of electricity from DG. *See id.* at 33–35.

precedent of regulating the number and type of fossil-fuel-fired DG units that can participate in demand response programs.[128] These limits include prohibiting the participation of fossil-fuel-fired DG near certain centralized generators and, elsewhere, capping the number of fossil-fuel-fired generators that could participate in the program.[129]

As part of the REV proceeding—as well as other proceedings involving DG—the NYPSC could push these rules further, including by using more sophisticated methodologies for regulating the amount of fossil-fuel-fired DG that can participate in demand response programs or that can be installed to help address grid constraints pursuant to a utility's Distributed System Implementation Plan. For example, the Environmental Impact Statement prepared for the REV proceeding envisioned limiting the number of fossil-fuel-fired DG resources that could sell electricity services at any particular electricity feeder[130]—an approach that would help prevent DG from becoming concentrated within a particular area.

Another approach would be to adjust the amount of DG that can receive market compensation based on the emissions impact of each participating DG unit. For example, the NYPSC could establish a daily, or even hourly, feeder-level "emissions cap" for certain localized pollutants. Distributed energy resource owners that use DG to reduce their electricity consumption from the grid would have to certify their emissions rate to the grid operator. The grid operator would then impute the emissions impact of demand response from that source based on the quantity of services that the unit provides to the grid.[131] Under this model, demand response resources that reduce consumption without using DG would have an emissions rate of zero. The grid operator could not accept any services that would cause the aggregate emissions from distributed

128 *See* Order Establishing Con Edison Demand Response Program, *supra* note 74.

129 *See id.*

130 *See* Final Generic Environmental Impact Statement, Case Nos. 14-M-0101, 14-M-0094, at 5–7, & Ex. 5-2 (N.Y. Pub. Serv. Comm'n Feb. 6, 2015).

131 A significant amount of demand response currently occurs through "aggregators"—entities that aggregate many small demand response providers into a large unit capable of providing a significant level of demand response. The involvement of aggregators would likely facilitate this approach, because they would be able to develop experience measuring and maintaining emissions levels for fossil-fuel-fired DG.

energy resources participating in a market in the relevant area to exceed the specified cap. By permitting cleaner generators to provide a greater share of electric services, this approach would create an incentive to install relatively clean DG, thereby reducing emissions from DG even on the days when the total DG emissions do not reach the feeder-level cap.

This approach to capping emissions from participation in market-based programs is not necessarily limited to the local grid operator. Although the NYPSC's statements in the REV proceeding and its proposal of the Part 222 regulations suggest that the NYPSC may be receptive to these policies, a similar approach could also be applied to demand response or any other services for which DG participates in the wholesale markets operated by the New York Independent System Operator (NYISO).[132] Indeed, to the extent that a significant amount of DG participates in the NYISO wholesale market, an ideal electricity-market-based approach would require some coordination between New York State and the NYISO.[133] One possible approach might be for the NYISO and the NYPSC to coordinate on an overall set of limits for a particular area. The NYSIO and the NYPSC could then each establish a cap equal to a subset of that limit for demand response programs likely to involve DG that it operates or oversees.

Neither the NYISO nor the NYPSC is a traditional environmental regulator with much experience with environmental concerns. As a result, it may make sense to implement the market

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132 Because the NYISO regulates at a different level of granularity then the NYPSC, any approach along these lines would necessarily look at a different regulatory increment than the feeder level. The nodal level, at which the NYISO currently regulates prices, would appear to be the natural substitute. *See TCC Reports*, N.Y. INDEP. SYS. OPERATOR, http://tcc.nyiso.com/tcc/public/view_nodal_prices.do (last visited Jan. 6, 2016) (listing nodal prices).

133 As discussed in the next paragraph of the text, NYISO is not an environmental regulator and thus any such effort is beyond its typical purview. NYISO, however, generally requires DR participating in its markets to comply with applicable environmental regulations and so some variant of this proposal could be more appealing if implemented as a means of facilitating, or enforcing compliance with, state or local environmental rules and regulations. *See, e.g.*, N.Y. INDEP. SYS. OPERATOR, EMERGENCY DEMAND RESPONSE PROGRAM MANUAL (2013), http://www.nyiso.com/public/ webdocs/markets_operations/ documents/Manuals_and_Guides/Manuals/Operations/edrp_mnl.pdf. *See also Environmental Advisory Council*, N.Y. INDEP. SYS. OPERATOR, http://www.nyiso.com/public/markets_operations/committees/eac/index.jsp (last visited Nov. 17, 2016) (discussing NYISO's consideration of environmental factors in carrying out its responsibilities).

rules described above through a cooperative program involving the NYSDEC and either the NYPSC or the NYISO, as appropriate. Under this approach the NYSDEC would use its environmental expertise and authority to set the limits on the amount of fossil-fuel-fired DG that can participate in programs, but then implement these limits through rules set and administered by the NYPSC or the NYISO, respectively.

The main drawback of this approach is that it would not address emissions from diesel generators that are merely responding to high prices—*i.e.*, operating whenever prices are high, in order to reduce demand from the grid, rather than participating in a particular program or tariff directly providing compensation for the use of the DG. It may prove more effective to address emissions from DG through the source-specific approaches discussed above in Section IV.A.1 that environmental regulators could implement.

B. *Options for Addressing GHG Emissions*

To the extent that GHG emissions from DG are a concern, their regulation should require a different approach. Unlike the emissions of conventional pollutants, the effects of GHGs are global, so there is no reason to focus on the emissions of GHGs in a particular area. Instead, the focus should be on limiting the total amount of GHG emissions, rather than limiting their emission in certain areas. Nevertheless, many of the policies discussed in the prior section would likely reduce the GHG emissions from increased use of DG, since those policies reduce or deter the use of relatively inefficient generators.[134] Accordingly, adopting one or more of the approaches listed above might reduce—or eliminate—the benefit of directly addressing GHG emissions from DG. Any jurisdiction that enacts regulations of conventional pollutants may want to carefully evaluate whether supplemental regulation of GHGs is worthwhile, especially if it appears that DG displaces relatively GHG-intensive methods of generation.

One option for addressing GHGs from fossil-fuel-fired DG is to extend any carbon-pricing scheme to smaller generators. In New York, this would likely mean extending the obligation to hold

134 The dynamic may work both ways—i.e., addressing GHG emissions from fossil-fuel-fired DG may also help to reduce their emissions of conventional pollutants.

RGGI permits below the current 25 MW threshold. This could take several forms. A relatively straightforward means for New York to do so would be to lower the threshold at which generators must acquire RGGI permits from the current 25 MW limit to 5 MW or even 1 MW.[135] New York might also consider requiring utilities or aggregators that rely on distributed generation to obtain RGGI permits roughly equivalent to the emissions that result from the activities on which the utility or the aggregator is relying, at least where the aggregate amount of demand response provided by fossil-fuel-fired DG exceeds some lowered threshold.[136] Both approaches have the advantage of piggybacking on the established RGGI market, likely reducing the start-up and administrative costs relative to pursuing an entirely new approach. Of course, any effort to modify RGGI itself—especially if it increases the number of sources that must hold permits—could prove politically challenging as it could require coordination with and assent from the other RGGI states.

Another option is to use the carbon price determined in the RGGI market, but without requiring small generators (or the utilities or DSPs on these small generators' behalf) to hold actual permits. This could take several forms. One option would be to use the cost of an RGGI permit as a shadow price in the DSP markets to be established under REV. The DSP could add the shadow price to any product or service offered into the DSP market that required the operation of fossil-fuel-fired DG. This approach would decrease the relative cost of less GHG-intensive products and, therefore, enable these services to clear the market, even if these services were more expensive than more GHG-intensive options absent the shadow price.[137]

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135 Alternatively, New York might also enact a separate permitting scheme that requires DG with a maximum output below the 25 MW limit, but above this new threshold, to secure permits that are priced at the same level as RGGI permits. This would incorporate the RGGI price signal, but without further reducing the number of available permits.

136 A challenge with this approach would be determining what demand response is provided by substituting fossil-fuel-fired DG versus simply a reduction in consumption. In practice, this approach would likely require utilities or aggregators to rely on certifications from the operators of these sources.

137 At the time of writing, NYPSC staff had issued a white paper proposing a Clean Energy Standard that would require utilities to secure a certain percentage of their electricity from renewable resources. Staff White Paper on Clean Energy Standard, Case No. 15-E-0302 (N.Y. Pub. Serv. Comm'n Jan. 25, 2016). To the extent that this proposal would create an implied price on electricity from GHG-

A third option is to adopt GHG-intensity standards—*i.e.*, standards that are tied to the rate of GHG emissions per unit of electricity produced. This could be similar to the CO_2 limits that Delaware imposes on eligible DG units.[138] Additionally, this approach might include a prohibition on the operation of certain classes of especially GHG-intensive DG or require that new DG installed within the state achieve a certain minimum level of efficiency. This approach would parallel NYCDEP's future requirement that diesel engines meet EPA's NSPS Tier 4 standards in order to secure a renewed operating permit. In considering this approach, however, it is important to consider the carbon-intensity of the potentially prohibited units to ensure that they are, in fact, more carbon intensive than the marginal central generator that they are likely to displace.[139] Otherwise, this approach could have the perverse effect of increasing aggregate GHG emissions.

CONCLUSION

Increased use of DG offers a number of potential advantages to grid operators and consumers of electricity, including economic, reliability, and environmental benefits. But significant increases in the amount of fossil-fuel-fired DG, especially DG that runs on diesel fuel, could negatively impact human health and the environment. Those concerns are particularly acute in urban areas, where heavy use of fossil-fuel-fired DG could contribute to "hotspots" for particular pollutants. Current regulations at the federal, state, and local levels only partially address these concerns. This Article has presented a variety of policy approaches that regulators might consider adopting to address these concerns more fully, but does not advocate for a particular approach. Given the relative lack of information about DG and the associated emissions, additional information about the fossil-fuel-fired DG units currently in operation and their emission impacts would be helpful in developing a comprehensive approach to this issue. In selecting among policy options, regulators should choose the

emitting resources, it may supplant any reason for including a shadow price derived from RGGI.

138 *See* 7 DEL. ADMIN. CODE § 1144-3.2 (2016).

139 As noted, because it avoids certain inefficiencies, such as line losses, electricity from fossil-fuel-fired DG can emit lower total levels of pollutants than centralized generation, even if the DG unit is less efficient per kilowatt-hour generated. *See supra* note 22 and accompanying text.

approach that makes the most sense based on the costs and benefits specific to the activities over which they have jurisdiction, mindful of the need to create a coherent approach to regulating emissions from DG.

CLE READING MATERIALS

Public Utilities Commission of Nevada Order – Investigation and Rulemaking to Implement Senate Bill 65 (2017)

FOR

10:15 a.m. – 11:35 a.m. **ADVANCING ENERGY POLICY**

- **Kathleen Frangione**, Chief Policy Advisor, Office of the Governor for the State of New Jersey
- **Cheryl LaFleur**, Commissioner, Federal Energy Regulatory Commission
- **Andrew G. Place**, Vice Chairman, Pennsylvania Public Utility Commission

Moderator: **Burcin Unel**, Energy Policy Director, Institute for Policy Integrity

PLEASE RETURN TO REGISTRATION TABLE

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Investigation and rulemaking to implement Senate Bill 65 (2017).	)))	Docket No. 17-07020

At a general session of the Public Utilities Commission of Nevada, held at its offices on August 15, 2018.

PRESENT: Chairman Joseph C. Reynolds
Commissioner Ann C. Pongracz
Commissioner Bruce H. Breslow
Assistant Commission Secretary Trisha Osborne

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

The Public Utilities Commission of Nevada ("Commission") opened a rulemaking docket, designated as Docket No. 17-07020, to implement Senate Bill 65 (2017) ("SB 65").

II. SUMMARY

The proposed regulation, appended hereto as Attachment 1, is adopted as a permanent regulation.

III. PROCEDURAL HISTORY

- On July 19, 2017, the Commission opened the rulemaking.
- This proceeding is being conducted pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 233B, 703, and 704, and SB 65.
- The Regulatory Operations Staff ("Staff") of the Commission participates as a matter of right pursuant to NRS 703.301.
- On September 27, 2017, the Commission issued a Notice of Rulemaking, Notice of Request for Comments, and Notice of Workshop.
- On October 11, 2017, the Attorney General's Bureau of Consumer Protection ("BCP"), Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy ("NV Energy"), Western Resource Advocates, the Environmental Defense Fund, and

Institute for Policy Integrity (collectively, "WRA et al."), and Staff (collectively, "Participants") filed comments.

- On October 17, 2017, WRA et al. filed Reply Comments.
- On October 18, 2017, the Presiding Officer held a workshop. The Participants and Angel De Fazio made appearances.
- On October 18, 2017, Staff and NV Energy filed Reply Comments.
- On October 19, 2017, NV Energy filed Corrected Reply Comments.
- On October 23, 2017, the Presiding Officer held an additional workshop. Participants made appearances, and the workshop was continued.
- On October 26, 2017, the Presiding Officer issued a Procedural Order.
- On November 14, 2017, the Presiding Officer issued Procedural Order No. 2.
- On November 20, 2017, WRA et al. and the Governor's Office of Energy filed comments and the Participants filed nearly consensus regulations.
- On December 1, 2017, the Presiding Officer held a continued workshop. Participants made appearances.
- On December 20, 2017, the Presiding Officer held a continued workshop. Participants made appearances.
- On March 26, 2018, the Presiding Officer sent proposed regulations to the Legislative Counsel Bureau ("LCB").
- On May 1, 2018, the Commission received revised regulations from LCB.
- On May 21, 2018, the Commission issued Procedural Order No. 3, requesting Staff produce a Small Business Impact Report regarding the revised regulations received back from LCB on May 1, 2018.
- On June 29, 2018, the Commission issued an Order finding that the proposed regulation is not likely to impose a direct and substantial economic burden upon small businesses nor is it likely to directly restrict the formation, operation, or expansion of a small business
- On July 2, 2018, the Commission issued a Notice of Intent to Act upon a Regulation, Notice of Workshop, and Notice of Hearing for Adoption, Amendment, and Repeal of Regulations of the Public Utilities Commission of Nevada.
- On July 24, 2018, Staff filed a letter with the Commission advising that it would not be filing Comments in response to the Notice issued on July 2, 2018.

- On July 25, 2018, the Participants filed Comments.
- On July 30, 2018, the Commission held a workshop pursuant to NRS 233B.061(2).
- On July 31, 2018, the Commission held a hearing pursuant to NRS 233B.061(3).

IV. REGULATION

1. The regulation, appended hereto as Attachment 1, implements SB 65 (2017). Under current regulation, each electric utility must submit to the Commission every 3 years an integrated resource plan to increase the utility's supply of electricity or decrease the demands made on its system by its customer. This regulation revises existing regulations governing the information required to be included in a utility's resource plan to require a utility to include in its plan certain information related to reducing customer exposure to the price volatility of fossil fuels and the potential costs of carbon.

2. Based on the foregoing, the Commission finds that it is in the public interest to adopt as permanent the proposed regulation appended hereto as Attachment 1.

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THEREFORE, it is ORDERED:

1. The proposed regulation, appended hereto as Attachment 1, is ADOPTED AS PERMANENT.

By the Commission,

JOSEPH C. REYNOLDS, Chairman

ANN C. PONGRACZ, Commissioner and Presiding Officer

BRUCE H. BRESLOW, Commissioner

Attest: Trisha Osborne
TRISHA OSBORNE,
Assistant Commission Secretary

Dated: Carson City, Nevada
8/20/18

(SEAL)

PUBLIC UTILITIES COMMISSION OF NEVADA PUC

ATTACHMENT 1

PROPOSED REGULATION OF THE

PUBLIC UTILITIES COMMISSION OF NEVADA

LCB File No. R060-18

August 15, 2018

EXPLANATION - Matter in *italics is* new; matter in *italics and underlined* is material inserted by the Commission; matter in brackets [omitted-material] is material to be omitted, matter in brackets and underline [omitted material] is material omitted by the Commission.

AUTHORITY: §§1-4, NRS 703.025, 704.210 and 704.741; §5, NRS 703.025, 704.210, 704.741 and section 1 of [Assembly] *Senate* Bill No. 65, chapter 383, Statutes of Nevada 2017, at page 2471 (NRS 704.744).

A REGULATION relating to electric utilities; requiring a resource plan submitted by an electric utility to contain certain information concerning the reduction of consumer exposure to the price volatility of fossil fuels and the potential social cost of carbon; establishing the method for calculating the social cost of carbon; requiring an electric utility to hold a meeting with certain parties and interested persons before filing a resource plan or an amendment to a resource plan; establishing requirements for providing notice of such a meeting; and providing other matters properly relating thereto.

Legislative Counsel's Digest:

Existing law requires each electric utility to submit to the Public Utilities Commission of Nevada every 3 years an integrated resource plan to increase the utility's supply of electricity or decrease the demands made on its system by its customers. (NRS 704.741) Under existing law, in determining the adequacy of a utility's resource plan, the Commission is required to give preference to those measures and sources of supply that provide the greatest economic and environmental benefits to the State, as well as those that provide for diverse electricity supply portfolios and which reduce customer exposure to price volatility of fossil fuels and the potential costs of carbon. In determining the preference given to such measures and sources of supply, existing law requires the Commission to consider the cost of those measures and sources of supply to the customers of the electric utility. (NRS 704.746) Finally, existing law requires any order of the Commission accepting or modifying a utility's resource plan or an amendment to such a plan to include the Commission's justification for the preferences given to those measures

and sources of supply. (NRS 704.751) **Sections 1-4** of this regulation revise existing regulations governing the information required to be included in a utility's resource plan to require a utility to include in its plan certain information related to reducing customer exposure to the price volatility of fossil fuels and the potential costs of carbon.

Existing regulations require that the resource plan be accompanied by a summary of the resource plan, including, without limitation, a summary of the preferred plan of the electric utility. (NAC 704.9215) **Section 1** of this regulation requires the summary of the preferred plan to include an explanation of how the preferred plan reduces consumer exposure to the price volatility of fossil fuels and the potential social cost of carbon.

Existing regulations require the environmental costs to the State associated with operating and maintaining a supply plan or demand side plan be quantified for air emissions, water and land use. (NAC 704.9359) **Section 2** of this regulation requires the environmental costs to the State associated with operating and maintaining a supply plan or demand side plan also to be quantified for the social cost of carbon.

Existing regulations require an electric utility to calculate the present worth of societal costs for each alternative plan for the supply of power submitted as part of the electric utility's supply plan, including environmental costs that are not internalized as private costs to the utility. (NAC 704.937) **Section 3** of this regulation requires that the social cost of carbon, excluding the cost from emissions of carbon internalized as private costs to the utility, be included in the calculation of such environmental costs. **Section 3** also requires an electric utility to determine the social cost of carbon using the values set forth in the "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis" released by the Interagency Working Group on Social Cost of Greenhouse Cases in August 2016. Additionally, **section 3** authorizes an electric utility to submit a calculation of the social cost of carbon using an alternative method if the electric utility provides information to support the alternative method and that method uses the best available science and economics and is equivalent in quality to the required method.

Existing regulations require a resource plan submitted by an electric utility to include certain graphs and tables regarding the electric utility's preferred plan and other supply plans. (NAC 704.945) **Section 4** of this regulation requires a resource plan to include a table showing the projected mix of generation by fuel type and the projected total emissions of carbon dioxide for each supply plan analyzed. **Section 4** also requires a resource plan to include a graph for each supply plan analyzed that shows, for each year of the resource plan, the percentage change in the preferred plan's projected total emissions of carbon dioxide resulting from that supply plan.

Existing law requires the Commission to require each electric utility to meet with personnel from the Commission and the Bureau of Consumer Protection in the Office of the Attorney General and any other interested persons to provide an overview of an anticipated filing or amendment to a resource plan. (Section 1 of [~~Assembly~~] *Senate* Bill No. 65, chapter 383, Statutes of Nevada 2017, at page 2471 (NRS 704.744)) **Section 5** of this regulation imposes this requirement on electric utilities.

Section 5 also requires an electric utility to prepare a notice for each such meeting and to take certain action to distribute the notice.

Section 1. NAC 704.9215 is hereby amended to read as follows:

704.9215 1. A utility's resource plan must be accompanied by a summary that is suitable for distribution to the public. The summary must contain easily interpretable tables, graphs and maps and must not contain any complex explanations or highly technical language. The summary must be approximately 30 pages in length.

2. The summary must include:

(a) A brief introduction, addressed to the public, describing the utility, its facilities and the purpose of the resource plan, and the relationship between the resource plan and the strategic plan of the utility for the duration of the period covered by the resource plan.

(b) The forecast of low growth, the forecast of high growth and the forecast of base growth of the peak demand for electric energy and of the annual electrical consumption, for the next 20 years, commencing with the year following the year in which the resource plan is filed, both with and without the impacts of programs for energy efficiency and conservation and an explanation of the economic and demographic assumptions associated with each forecast.

(c) A summary of the demand side plan listing each program and its effectiveness in terms of costs and showing the 20-year forecast of the reduction of demand and the contribution of each program to this forecast.

(d) A summary of the preferred plan [~~showing~~] :

(1) Showing each planned addition to the system for the next 20 years, commencing with the year following the year in which the resource plan is filed, with its anticipated capacity, cost and date of beginning service ~~[.]~~ ; ***and***

(2) Explaining how the preferred plan reduces customer exposure to the price volatility of fossil fuels and the potential social cost of carbon as calculated pursuant to subsection 5 of NAC 704.937 and, if applicable, subsection 6 of that section.

(e) A summary of renewable energy showing how the utility intends to comply with the portfolio standard and listing each existing contract for renewable energy and each existing contract for the purchase of renewable energy credits and the term and anticipated cost of each such contract.

(f) A summary of:

(1) The energy supply plan for the next 3 years setting out the anticipated cost, price volatility and reliability risks of the energy supply plan;

(2) The risk management strategy;

(3) The fuel procurement plan; and

(4) The purchased power procurement plan.

(g) A summary of the activities, acquisitions and costs included in the action plan of the utility.

(h) An integrated evaluation of the components of the resource plan which relates the preferred plan to the objectives of the strategic plan of the utility, and any other information useful in presenting to the public a comprehensive summary of the utility and its expected development.

Sec. 2. NAC 704.9359 is hereby amended to read as follows:

704.9359 The environmental costs to the State associated with operating and maintaining a supply plan or demand side plan must be quantified for air emissions, water and land use ~~[.]~~ ***and the social cost of carbon as calculated pursuant to subsection 5 of NAC 704.937 and, if applicable, subsection 6 of that section***. Environmental costs are those costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan.

Sec. 3. NAC 704.937 is hereby amended to read as follows:

704.937 1. A utility's supply plan must contain a diverse set of alternative plans which include a list of options for the supply of capacity and electric energy that includes a description of all existing and planned facilities for generation and transmission, existing and planned power purchases, and other resources available as options to the utility for the future supply of electric energy. The description must include the expected capacity of the facilities and resources for each year of the supply plan. At least one alternative plan must be of low carbon intensity and include:

(a) The generation or acquisition of an amount of renewable energy greater than required by NRS 704.7821;

(b) Changes to the utility's existing fleet of resources for the generation of power;

(c) The application of technology that would significantly reduce emissions of carbon; or

(d) Any combination thereof.

2. A utility shall identify the criteria it has used for the selection of its options for meeting the expected future demands for electric energy and shall explain how any conflicts among criteria are resolved.

3. In comparing alternative plans containing different resource options, the utility shall calculate the present worth of future requirements for revenue for each alternative plan for the supply of power. A comparison of the present worth of future requirements for revenue for each alternative plan must be presented in the resource plan. As calculated pursuant to this subsection, the present worth of future requirements for revenue for each alternative plan must include, without limitation, a reasonable range of costs associated with emissions of carbon in the 20-year period of the resource plan as private costs to the utility.

4. The utility shall calculate the present worth of societal costs for each alternative plan for the supply of power. The present worth of societal costs of a particular alternative plan must be determined by adding the environmental costs that are not internalized as private costs to the utility pursuant to subsection 3 to the present worth of future requirements for revenue. ***In calculating the present worth of societal costs for each alternative plan pursuant to this subsection, the utility shall include as environmental costs the utility's estimate of the level of environmental costs resulting from carbon dioxide emissions for that year and the social cost of carbon.***

5. For the purposes of subsection 4 and NAC 704.9215 and 704.9359, the social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton

of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics ~~[and]~~ such as the analysis set forth in the "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis" released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016. This publication may be obtained, free of charge, at the Internet website https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf.

6. [~~In addition to calculating the social cost of carbon pursuant to subsection 5, the utility may calculate the social cost of carbon using an alternative method if:~~

~~(a) The alternative method uses the best available science and economics and is of equivalent quality to the method used in subsection 5; and~~

~~(b)~~] The utility must provide[~~s~~] information to support the use of [~~such an alternative method~~] any method used to calculate the social cost of carbon pursuant to subsection 5.

7. The utility shall consider for each alternative plan the mitigation of risk by means of:

(a) Flexibility;

(b) Diversity;

(c) Reduced size of commitments;

(d) Choice of projects that can be completed in short periods;

(e) Displacement of fuel;

(f) Reliability;

(g) Selection of fuel and energy supply portfolios; and

(h) Financial instruments or electricity products.

[~~6.~~] *8.* The alternative plans of the utility must:

(a) Provide adequate reliability;

(b) Be within regulatory and financial constraints;

(c) Meet the portfolio standard; and

(d) Meet the requirements for environmental protection.

[~~7.~~] *9.* The utility shall identify its preferred plan and fully justify its choice by setting forth the criteria that influenced the utility's choice.

Sec. 4. NAC 704.945 is hereby amended to read as follows:

704.945 1. A utility shall include in its resource plan a table of loads and resources for each supply plan analyzed. The table must include the following data for each year of the resource plan:

(a) The capacity provided by each supply resource;

(b) The total expected capacity of all resources;

(c) The forecasted peak demand;

(d) The estimated impact of new programs for energy efficiency and conservation;

(e) The expected capacity and energy provided by renewable resources, categorized by type;

(f) The required planning reserves;

(g) The total capacity required;

(h) The excess or deficiency of capacity without additional resources; and

(i) The excess or deficiency of capacity with additional planned resources.

2. A graph must be included for the preferred plan of the utility showing, over the 20-year planning period:

(a) The total resources requirements;

(b) The total demand without new programs for energy efficiency and conservation;

(c) The total demand with new programs for energy efficiency and conservation;

(d) The total capacity with additional planned resources; and

(e) The total capacity without additional resources.

3. A graph must be included for the preferred plan that shows, for each year of the 20-year planning period, the excess or required capacity both with and without the additional planned resources.

4. A table must be included for each supply plan analyzed that shows, for each year of the resource plan:

(a) The projected mix of generation by fuel type; and

(b) The projected total emissions of carbon dioxide.

5. A graph must be included for each supply plan analyzed that shows, for each year of the resource plan, the percentage change in the preferred plan's projected total emissions of carbon dioxide resulting from that supply plan.

6. A graph or table must be provided that shows the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers.

Sec. 5. NAC 704.952 is hereby amended to read as follows:

704.952 1. A utility may schedule sessions for reviewing plans and providing an

opportunity for interested persons to:

(a) Learn of progress by the utility in developing plans and amendments to plans;

(b) Determine whether key assumptions are being applied in a consistent and acceptable manner;

(c) Determine whether key results are reasonable; and

(d) Offer suggestions on other matters as appropriate.

2. If the utility, the Bureau of Consumer Protection in the Office of the Attorney General, the staff or any other person participating in the process cannot agree to *schedule sessions* for reviewing plans, any of those persons may petition the Commission to schedule *the* sessions.

3. The parties involved in the review sessions may establish, at the beginning of the sessions, a procedure to resolve any technical issues that are discussed during the sessions.

4. If review sessions are held pursuant to subsection 1, the utility shall prepare a brief summary of the major topics on the agendas and the conclusions reached by the parties during the review sessions. The summary must be provided to the Commission in conjunction with testimony supporting the utility's plan.

5. [~~At least~~] ***Not less than*** 4 months before [~~the anticipated date for~~] filing [~~the resource~~] **a** plan ~~[,]~~ ***required by NRS 704.741, or within a reasonable period before filing an amendment to such a plan pursuant to NRS 704.751,*** the utility shall meet with staff, [~~and~~] the personnel of the Bureau of Consumer Protection ***and any other interested persons*** to provide an overview of the [~~anticipated filing~~] ~~[.]~~ ***plan or amendment.***

6. [~~Before a utility may file an amendment to its resource plan, the utility must meet with staff and the personnel the Bureau of Consumer Protection to provide an overview of the~~

~~anticipated amendment.~~] ***For each meeting held pursuant to subsection 5, the utility shall prepare a notice of the meeting which must include, without limitation, the date, time and location of the meeting and an explanation of the purpose of the meeting. The utility shall distribute the notice by:***

(a) Posting the notice on the Internet website of the utility;

(b) Sending the notice via electronic mail to each person on the relevant service list maintained by the Commission; and

(c) Providing the notice to staff of the Commission for publication on the Internet website of the Commission.

CLE READING MATERIALS

Muddling Through Modern Energy Policy: The Dormant Commerce Clause and Unmaking the Illusion of an *Attleboro* Line

FOR

10:15 a.m. – 11:35 a.m. **ADVANCING ENERGY POLICY**

- **Kathleen Frangione**, Chief Policy Advisor, Office of the Governor for the State of New Jersey
- **Cheryl LaFleur**, Commissioner, Federal Energy Regulatory Commission
- **Andrew G. Place**, Vice Chairman, Pennsylvania Public Utility Commission

Moderator: **Burcin Unel**, Energy Policy Director, Institute for Policy Integrity

PLEASE RETURN TO REGISTRATION TABLE

MUDDLING THROUGH MODERN ENERGY POLICY: THE DORMANT COMMERCE CLAUSE AND UNMASKING THE ILLUSION OF AN *ATTLEBORO* LINE

SAM KALEN*

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INTRODUCTION

The country's transition to a green economy is haunted by a lingering ghost. Our energy policy has emerged as a mélange of often-discordant policies designed to achieve narrow objectives. New policies, after all, generally respond to acute crises, some of which may be real, some occasionally merely perceived, or some possibly long since passed. That has been the fate of energy policy.[1] As the nation explores avenues for reducing greenhouse

* Winston S. Howard Distinguished Professor, University of Wyoming College of Law. The author would like to thank Dan Tarlock, James E. Hickey, Jr., Stephen Feldman, and Robert R. Nordhaus for their helpful comments and

gas emissions and transitioning to a low or zero carbon future in both the transportation and electric generation sectors, it must confront embedded obstacles—policy choices that have become infused in a legal architecture, an architecture that correspondingly incents financial markets, and markets that then support infrastructure development.

When the United States Supreme Court decided *Public Utilities Commission v. Attleboro Steam & Electric Co.*,[2] that is what happened. In 1927, the court held that the Constitution's implied Dormant Commerce Clause prohibits states from regulating rates for the sale of electricity across state lines.[3] That decision prompted the passage of the Federal Power Act (FPA) eight years later,[4] and the unfortunate and suspect ghost of *Attleboro* that haunts us today.

Since then, judges routinely invoke *Attleboro* to draw a jurisdictional line between local distribution and wholesale sales where electrons might flow in interstate commerce.[5] In 1953, Justice Reed explained how *Attleboro*

established what has unquestionably become a fixed premise of our constitutional law but what was not all clear in 1920, that the Commerce Clause forbade state regulation of some utility rates. State power was held not to extend to an interstate sale "in wholesale quantities, not to consumers, but to distributing companies for resale to consumers.[6]

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suggestions. The author greatly appreciates all the effort and assistance from the staff at the NYU Environmental Law Journal.

1 *See generally* Sam Kalen, *Embedded Choices: A Resilient Energy Legal Architecture*, 52 IDAHO L. REV. 390 (2015).

2 *See* Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927).

3 *See id.* at 89.

4 *See* Pub. L. No. 74-333, 49 Stat. 803, 847–63 (1935) (codified as amended at 16 U.S.C. ch. 12 (2012)).

5 *See* Jersey Cent. Power & Light Co. v. Fed. Power Comm'n, 319 U.S. 61, 87 (1943); Conn. Light & Power Co. v. Fed. Power. Comm'n, 324 U.S. 515, 524, 526 (1945); United States v. Pub. Utils. Comm'n, 345 U.S. 295, 303 (1953); Fed. Power Comm'n v. S. Cal. Edison, 376 U.S. 205, 212 (1964); Fed. Power Comm'n v. Fla. Power & Light Co., 404 U.S. 453, 458 (1972); New York v. FERC, 535 U.S. 1, 19 (2002). *See generally* James E. Hickey, Jr., *Mississippi Power & Light Company: A Departure Point for Extension of the "Bright Line" Between Federal and State Regulatory Jurisdiction over Public Utilities*, 10 J. ENERGY L. & POL'Y 57 (1989) (discussing federal preemptive power in *Mississippi Power & Light Co. v. Moore*, 487 U.S. 354 (1988)).

6 United States v. Pub. Utils. Comm'n, 345 U.S. 295, 303 (1953).

In *New York v. FERC*, the Supreme Court observed how, when the court earlier held that state regulation of electricity moving between states directly burdened interstate commerce, it created "what has become known as the '*Attleboro* gap'."[7] Indeed, judges today seemingly feel duty bound to begin their analyses by recounting this history.[8] The *Attleboro* line, therefore, has become the *sine qua non* of many contemporary discussions, and it infuses Dormant Commerce Clause considerations into modern state and local efforts to encourage renewable energy development within their borders.[9] It also recently surfaced in the Supreme Court's consideration of whether the Federal Energy Regulatory Commission (FERC) may influence demand-site management programs (encouraging lower energy use and energy efficiency).[10]

This article explores how the illusion surrounding *Attleboro* surfaced and generated the ghost of *Attleboro* that still influences modern efforts to transition to a green economy. Twenty-five years ago, historian Morton Keller observed how "[o]ur public utilities . . . operate under the regulatory system and legal conditions created during the decades before 1930," and while technology has changed considerably since then, "the regulatory and legal response has not deviated significantly from the earlier experience."[11] While that is no longer true for the decades since he penned those thoughts,[12] it seems like an auspicious moment to remove an additional lingering vestige from that era—our ghost. *Attleboro* is useful when explaining what prompted the eventual passage of the FPA, but the language, intent, structure, and purpose of the FPA are what governs today, not *Attleboro*. After all, contemporary constitutional narrative did not compel the decision, and constitutional principles as they evolved shortly thereafter undermined the Supreme Court's rationale. Indeed, the court's analysis is, at best, dubious. It implicitly accepted a doctrine that the court had just undermined, and the opinion is too abstract to justify what has since become the *Attleboro* line

7 535 U.S. at 6.

8 *See, e.g.*, N.J. Bd. of Pub. Utils. v. FERC, 744 F.3d 74, 80 (3d Cir. 2014).

9 *See infra* notes 305–313 and accompanying text.

10 *See infra* notes 314–321 and accompanying text.

11 MORTON KELLER, REGULATING A NEW ECONOMY: PUBLIC POLICY AND ECONOMIC CHANGE IN AMERICA, 1900–1933, at 228 (1990).

12 *See infra* notes 299–303 and accompanying text. *See generally infra* note 317.

distinguishing between wholesale and retail sales. The FPA, instead, establishes the now governing boundary, partly because Justice Sanford's all-too cryptic analysis in *Attleboro* demanded more clarity and partly because the FPA's line was the one advocated by the Federal Power Commission (FPC) and others. Our *Attleboro* ghost, therefore, deserves to be "busted" and laid to rest.

This Article illustrates why *Attleboro* deserves far less attention than it has received, and how the opinion is relevant only for explaining the history of federal energy policy prior to the 1930s. Part I of the Article begins by chronicling the rise of the electric central generating station, as well as the influence of progressivism on the need for regulatory constraints for emerging industries such as the electric utility industry. Part II then explores the constitutional narrative surrounding the appropriate level of regulatory oversight, whether at the federal or state level, and why vacillating Dormant Commerce Clause jurisprudence lacked sufficiently clear guidance for regulating the interstate electric grid. Part III reviews how those options became tested in what seemed like an unimportant contract dispute between utilities in different states, a dispute that occurred amid a national dialogue about the development of a large, interstate, grid dubbed a superpower. This Part, in particular, examines the court's analysis in *Attleboro*, and why that analysis is both suspect and not necessarily prescribed by the prevailing Dormant Commerce Clause narrative. The Article ends by positing that, while *Attleboro* influences modern dialogues, its ghost ought to be relegated to the history pages rather than prominently displayed as a component of any legal argument.

I. CITIES, PROGRESSIVISM, AND ELECTRICITY MARKETS

A. *Electricity Lights a Fair*

When President Cleveland ceremoniously closed the circuit, electrifying the great White City in May 1893,[13] the nation's policy toward energy law began on its path toward a collision course with the future. Chicago's great fair of the 19th century, named the White City, perhaps best captures how energy resources

13 *See* ERIK LARSON, THE DEVIL IN THE WHITE CITY 238 (2003).

would become the foundation for America's "progress."[14] Celebrating the 400th anniversary of Christopher Columbus, the World's Columbian Exposition of 1893 demonstrated how planning, urban life, and electricity combined to illustrate democracy's progress.[15] "The buildings would be lit with 7,000 arc and 120,000 incandescent lamps, which would be among the most striking technologies on display, demonstrating the newfangled wonders of electricity."[16] An "Electricity" building was one structure housed within this diminutive city.[17] This fair, moreover, "outshone" all others, attracting over 27 million visitors.[18] "It was also the most electrified world affair ever held, requiring three times the electricity used to power Chicago on a daily basis and ten times the electrical power used at the 1889 Paris Exposition."[19] And it displayed how nascent technology capable of converting alternating current (AC) to direct current (DC) could power cities, allowing a large generating station to produce high voltage energy

14 This transient replica of a surreal city "into which on some days about three-quarters of a million people crowded, represented the best that America could offer—a city intelligently designed for comfort, convenience, and beauty." HAROLD U. FAULKNER, POLITICS, REFORM AND EXPANSION 1890–1900, at 33 (1959).

15 *See* WILLIAM CRONON, NATURE'S METROPOLIS: CHICAGO AND THE GREAT WEST 341–69 (1991). *See also* SEAN D. CASHMAN, AMERICA IN THE GILDED AGE 164–65 (1993) (observing how the World's Fair endorsed Edward Bellamy's vision in *Looking Backward* and represented what city planning could do for urban living).

16 CRONON, *supra* note 15, at 341–42. Westinghouse provided the electricity, while Thomas Edison who lost that contract secured the ability to light "the fairgrounds with tens of thousands of his incandescent bulbs." W.H. BRANDS, AMERICAN COLOSSUS: THE TRIUMPH OF CAPITALISM, 1865–1900, at 511 (2010).

17 *See* NORMAN BOLOTIN & CHRISTINE LAING, THE WORLD'S COLUMBIA EXPOSITION: THE CHICAGO WORLD'S FAIR OF 1893, at 78–80 (1992). Amidst what one of President Theodore Roosevelt's biographer's calls "a showcase for the revolutionary marvels of harnessed electricity," Roosevelt ensured the fair would pay some homage to a western ideal. DOUGLAS BRINKLEY, THE WILDERNESS WARRIOR: THEODORE ROOSEVELT AND THE CRUSADE FOR AMERICA 257–58 (2009).

18 BOLOTIN & LAING, *supra* note 17, at vii.

19 *Id.* at 8. "When cultural historians look back at the fair, . . . what they see . . . was the glittering arrival of electricity." PHILLIP F. SCHEWE, THE GRID: A JOURNEY THROUGH THE HEART OF OUR ELECTRIFIED WORLD 53 (2007). Social historians, however, see how the fair masked underlying economic problems and delayed temporarily Chicago from experiencing the 1893 recession. *See* RAY GINGER, ALTGELD'S AMERICA: THE LINCOLN IDEAL VERSUS CHANGING REALITIES 92 (1973).

that could then be used for powering the fair's attractions.[20]

At the cusp of the progressive era, Chicago—the "electric city"[21]—and its World's Fair exemplified how technology and demographics became symbiotic with the new economy and its capital concentration, wage laborers, interstate markets and, commensurately, the vertically integrated and centralized electric power grid. 1893, after all, was the year when Emile Durkheim wrote how "science can help us adjust ourselves, determining the ideal toward which we are heading confusedly."[22] The ability to transport products across the nation's railways, to communicate over telegraph wires and through the mail, and to travel with the automobile made it such that "[c]ity and country were growing closer together."[23] But not until the rural electrification movement following WWI would the countryside begin to experience the transformative power of electric energy.[24] The cities, instead, with their rising populations, factories, and burgeoning electric trollies, propelled the need for electric generation.[25] Concentrating

20 *See* Richard D. Cudahy & William D. Henderson, *From Insull to Enron*: *Corporate (Re)Regulation After the Rise and Fall of Two Energy Icons*, 26 ENERGY LAW J. 35, 45 (2005). Several books explore Edison's contributions to the birth of the modern electric system, his battle with others over his support for DC as opposed to AC current, as well as his life. For some of the better ones exploring Edison and the development of electricity, see generally ROBERT L. BRADLEY JR., EDISON TO ENRON 19 (2011); ERNEST FREEBERG, THE AGE OF EDISON (2013); CHRISTOPHER JONES, ROUTES OF POWER 194–226 (2014) ("The Electrification of America"); THOMAS P. HUGHES, NETWORKS OF POWER (1983); JILL JONES, EMPIRES OF LIGHT: EDISON, TESLA, WESTINGHOUSE, AND THE RACE TO ELECTRIFY THE WORLD (2003); MAURY KLEIN, THE POWER MAKERS (2009); DAVID E. NYE, ELECTRIFYING AMERICA 139 (1990); HAROLD L. PLATT, THE ELECTRIC CITY (1991); SCHEWE, *supra* note 19; JOHN F. WASIK, THE MERCHANT & POWER: SAMUEL INSULL, THOMAS EDISON, AND THE CREATION OF THE MODERN METROPOLIS (2006).

21 BRADLEY, *supra* note 20, at 151. Insull even started Chicago's *Electricity City* magazine to encourage consumer demand for electrical appliances. *See* SCHEWE, *supra* note 19, at 70.

22 EMILE DURKHEIM, THE DIVISION OF LABOR IN SOCIETY 34 (G. Simpson trans., 1933). 1893 also began the realignment and transformation of political parties. *See* JOEL H. SILBEY, THE AMERICAN POLITICAL NATION, 1838–1893, at 234–35, 238 (1991).

23 CRONON, *supra* note 15, at 332–33. *See also* FAULKNER, *supra* note 14, at 49.

24 *See generally* RONALD R. KLINE, CONSUMERS IN THE COUNTRY (2000).

25 The nation's cities' growth "remains the most arresting demographical development of" the Nineteenth Century's last decade and it occurred in a "rapid and chaotic" manner. FAULKNER, *supra* note 14, at 10, 23. By the end of the century, moreover, most of the nation's wealth was concentrated in urban

ownership and control over that generation, and what would become the electric grid, seemed almost pre-ordained. Henry Demarest Lloyd, a writer for the *Chicago Tribune*, years earlier published his *Atlantic Monthly* article indicting the concentration of power in the railroad and oil industries,[26] followed by his 1894 *Wealth Against Commonwealth*.[27] His *Atlantic* article explored how Americans suffered economically as a consequence of Standard Oil Company's monopolization of petroleum, fixing its prices in U.S. cities (excluding New York) and controlling all the pipelines and transportation networks.[28]

That the electric grid would follow suit seemed natural, particularly once Samuel Insull demonstrated how his emerging empire could efficiently deliver low cost power to Chicago consumers.[29] Insull "ingeniously developed the business model to affordably bring electricity into homes, stores, offices, and industry" and was the "father of the modern electricity industry."[30] He promised to provide affordable electricity to the masses, by capitalizing on the economies of scale associated with large

centers—among manufacturers. *See id*. at 55, 72. Arthur Schlesinger would a few decades later portray the city as the pinnacle of progress and counterpart to Frederick Jackson Turner's thesis on the closing of the frontier. *See* ARTHUR M. SCHLESINGER, THE RISE OF THE CITY, 1878–1898 (1933). It was during the fair, after all, when Turner delivered his remarks. *See* GINGER, *supra* note 19, at 22. And for Chicago manufacturers, for instance, their use of electricity in the factories grew from 4 to 78% between 1900 and 1930. *See* SCHEWE, *supra* note 19, at 77.

26 *See* Henry Demarest Lloyd, *The Story of a Great Monopoly*, ATLANTIC MONTHLY (March 1881).

27 *See* HENRY DEMAREST LLOYD, WEALTH AGAINST COMMONWEALTH (1894).

28 *See Lloyd*, *supra* note 26. "*Atlantic* commentary," however, apparently "distribute[d] blame for the corruption of the political process, for rising class conflict, and for the destruction of social and cultural values fairly evenly between labor and capital." ELLERY SEDGWICK, A HISTORY OF THE ATLANTIC MONTHLY, 1857–1901, at 197 (2009). *See generally* BRUCE BRINGHURST, ANTITRUST AND THE OIL MONOPOLY: THE STANDARD OIL CASES, 1890–1911, at 108–10 (1979) (summarizing the company's influence by 1900). The Supreme Court, in 1911, issued a decree breaking up Standard Oil. *See* Standard Oil Co. of N.J. v. United States, 221 U.S. 1 (1911).

29 *See* BRADLEY, *supra* note 20, at 148. Increased demand, lower rates, and control over the market also became Insull's approach for saving his gas business—People's Gas. *See id.* at 155–59.

30 BRADLEY, *supra* note 20, at 19. Judge Cudahy and Professor Henderson provide a useful portrait of the history surrounding Insull and Edison. Cudahy & Henderson, *supra* note 20, at 39–72. *See also* FOREST MCDONALD, INSULL: THE RISE AND FALL OF A BILLIONAIRE UTILITY TYCOON (2004).

centralized generating stations that would service large areas, rather than smaller stations serving highly localized areas.[31] He encouraged utilities to agree to state public utility supervision of energy rates (cost of service with a rate of return) in return for an exclusive franchise guaranteeing the exclusive right to serve a territory.[32] For him, regulatory rate supervision posed little risk, because he favored selling energy as low as possible, even "ridiculously" low, in order to ensure that electricity would become a necessity.[33] Of course, while the majority of the population at this time still lived outside of urban centers, the "city" was fast becoming the loci of interest, control, and power. It is not surprising, therefore, that cities were the drivers of development of large-scale energy capacity to feed the needs of mass production, lighting, electric trolleys, and consumers.[34] A lecturer in London in 1893 observed how a central station worked well for large towns due to

> the great inconvenience of generating power in the small quantity and at the irregular times at which it is wanted for many purposes. For good or for ill, population gathers into huge communities, in which there is a complex development of social and industrial life. In such communities there is a constantly increasing need of mechanical power. In addition to manufacturing operations, demands for power arise for transit, for handling goods, for passenger lifts, for water supply, and for sanitation. At first these are met by the erection of scattered motors. But this sporadic production of power in small

31 *See* Cudahy & Henderson, *supra* note 20, at 39–72. Edison too recognized that small electric generators would be uneconomical and "saw the future in *jumbo* generators." *Id*. at 42. This model required sufficient demand (load), and the utilities therefore championed new electrical appliances and abandoning on-site generation—today, distributed generation. *See* BRADLEY, *supra* note 20, at 151. This fit nicely and became embedded in the new consumer economy—all of which flourished in the 1920s. *See* WILLIAM LEACH, LAND OF DESIRE (1993).

32 *See* NYE, *supra* note 20, at 180–81. Insull "crusade[d] to convince the industry to accept rate regulation in return for franchise protection." BRADLEY, *supra* note 20, at 172; *see also id*. at 86–88, 123–26; SCHEWE, *supra* note 19, at 69 (referring to a "Faustian Bargain"). *See generally* Forest McDonald, *Samuel Insull and the Movement for State Utility Regulatory Commissions*, 32 BUS. HIST. REV. 241 (1958).

33 MCDONALD, *supra* note 30, at 104.

34 From the Civil War to 1920, the cities experienced the fastest growth, with workers gravitating toward manufacturing and the extractive industries rather than agriculture. *See* MELVYN DUBOSKY, INDUSTRIALISM AND THE AMERICAN WORKER 1865–1920, at 3 (1996); *see generally* EDWARD GLAESER, TRIUMPH OF THE CITY (2011).

> quantities is quite certainly in many instances extravagantly costly and inconvenient. There is a great probability that power distributed from a central station in towns would be so convenient as to be preferable to power produced locally, even at a somewhat greater cost.[35]

This model, in turn, required developing a transmission infrastructure capable of carrying electricity to specified regions.[36] And by owning, controlling, or influencing all facets from the fuel source to production and distribution[37]—in short by becoming vertically integrated—Insull could build his empire. "Insull's empire," therefore, included "manufactured (coal) gas distribution, natural gas transmission, and urban transportation (a major user of power)."[38] And between the early 1900s and the 1920s, the delivery of electricity shifted from a primarily municipal (street lighting) and industrial base to an economy-wide customer base.[39]

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35 WILLIAM C. UNWIN, HOWARD LECTURES: ON THE DISTRIBUTION AND TRANSMISSION OF POWER FROM CENTRAL STATIONS 5 (1894).

36 "Early generating stations produced direct current, which could only serve a small area. With the introduction of alternating current in the 1890s this technical situation changed, permitting long-distance transmission of current." NYE, *supra* note 20, at 139; *see also* Glaeser, *supra* note 34, at 49–52. And by 1920, transmission lines of 100 miles were "common," and those of "up to 250 miles in length are known and regarded as practical." CHESTER G. GILBERT & JOSEPH E. POGUE, AMERICA'S POWER RESOURCES 176 (1921). "The introduction of electric-power transmission not only provided a means of supplying distant manufacturing and domestic demands, but also opened up an entirely new power field, namely, the operation of street railways and lighting plants . . . ." COMM'R OF CORPS., DEP'T OF LABOR & COMMERCE, WATER-POWER DEVELOPMENT IN THE UNITED STATES 1 (1912). As of approximately 1912, the apparent limit (primarily economic) for a transmission line was roughly 200 miles. *See id*. at 8, 86. The limit increased to between 300 and 500 miles by 1931. *See* William H. Rose, *Control of Super-Power*, 80 U. PA. L. REV. 153, 153 n.2 (1931).

37 *See* BRADLEY, *supra* note 20, at 97.

38 BRADLEY, *supra* note 20, at 19. Insull also recognized the value of electric streetcars, which "played a central role in developing larger electrical-generation plants in most American cities." NYE, *supra* note 20, at 92. Like their electric utility counterparts, streetcar companies (whose profitability diminished after the war) became centralized with usually one company per city and operated through a holding company. *See id*. at 91, 134. And they often served as a primary consumer of electric power. *See* W.S. MURRAY ET AL, U.S. GEOLOGICAL SURVEY., A SUPERPOWER SYSTEM FOR THE REGION BETWEEN BOSTON AND WASHINGTON 33 (1921) (half of New York's energy was consumed by its trolley). Insull, therefore, pursued supplying electricity to the Chicago electric transportation market as well. *See* SCHEWE, *supra* note 19, at 68.

39 *See* NYE, *supra* note 20, at 56, 261. "Nationally, as late as 1905 less than 10 percent of all motive power was electrical; by 1930 the figure had jumped to 80 percent." *Id*. at 13. And "[t]he electrification of the domestic market began in

It also moved outward, from the city hub toward surrounding areas and neighboring states.[40] Its web expanded, as well, through agreements with other utilities to pool their resources to ensure an adequate and reliable supply of electricity, rather than building unnecessary generating stations.[41]

B. *The Progressive Tendency Toward Federal Supervision*

The expanding electric grid occurred while governmental supervision of our nation's energy resources was swiftly becoming aligned with Progressivism, tempered marginally by those fearful of encroaching upon state authority.[42] A fundamental tenant for many early twentieth century Progressives was scientific planning and an enhanced role for the government vis-à-vis the regulation of social and economic relations.[43] They "embraced" change and, according to William Wiecek, "sensed that the traditional, local, small town, agrarian, individualist society and mores of the

earnest only after 1918." *Id*. at 265. The growth of central generation stations grew after 1910, and overall electric consumption "more than doubled" in the 1920s. RONALD E. SEAVOY, AN ECONOMIC HISTORY OF THE UNITED STATES: FROM 1607 TO THE PRESENT 268 (2006). The 1920s, therefore, "saw more capital expenditure on electricity than any other single decade of spending during the railroad boom of the previous century." SCHEWE, *supra* note 19, at 109.

40 *See* BRADLEY, *supra* note 20, at 143, 160–62. *See also* MCDONALD, *supra* note 30, at 139–42 (describing Insull's success in connecting outlying communities and diversifying the central station load).

41 *See* BRADLEY, *supra* note 20, at 162.

42 *See* KELLER, *supra* note 11, at 162.

43 *See generally* ARTHUR S. LINK & RICHARD L. MCCORMICK, PROGRESSIVISM (1983); MICHAEL MCGERR, A FIERCE DISCONTENT: THE RISE AND FALL OF THE PROGRESSIVE MOVEMENT IN AMERICA 1870–1920 (2003). "Progressives promoted the growth of government power and a shift from distributive policies into regulative channels that demanded technical expertise and well-developed budgeting and financial skills, rather than the more generalist negotiating talents" characteristic of the previous dominance of political parties. SILBEY, *supra* note 22, at 240. As a consequence of the "[c]haotic urban growth produced by rapid industrialization," order in the cities demanded "expert, scientific" managers rather than municipal control by mere political affiliation. MAUREEN A. FLANAGAN, AMERICA REFORMED: PROGRESSIVES AND PROGRESSIVISMS 1890s–1920s, at 81–82 (2007). For other sources on the Progressive Movement, *see generally* DUBOSKY, *supra* note 34; GEORGE E. MOWRY, THE ERA OF THEODORE ROOSEVELT (1958); AMERICAN PROGRESSIVISM: A READER (Ronald J. Pestritto, William J. Atto, eds., 2008). *See also* J. Leonard Bates, *Fulfilling American Democracy: The Conservation Movement, 1907–1921*, 44 MISS. VALLEY HIST. REV. 29, 30 (1957) ("There was another side to the Progressive Movement—perhaps the most significant side: the decline of laissez faire, the development of a social conscience, the repudiation of Social Darwinism.").

nineteenth century were passing away, to be replaced by a national integrated economy driven by technological change."[44] Many believed in "the need for federal leadership" to usher in technological change.[45] While active federal involvement began during the second half of the 19th century, the cascade of federal legislation occurred shortly thereafter. In 1900, Congress passed the Lacey Act to help facilitate state programs designed to prohibit interstate transport of illegally obtained wildlife.[46] Three years later, when the Supreme Court upheld the interstate transportation of lottery tickets, "Congress took very swift advantage of the new field thus opened to it" and passed a variety of programs.[47] In the economic realm, it passed the 1906 Hepburn Act,[48] the Mann-Elkins Act in 1910 extending the authority of the Interstate Commerce Commission to the telegraph and telephone industries,[49] the Federal Reserve Act of 1913,[50] and the Federal

44 WILLIAM M. WIECEK, THE LOST WORLD OF CLASSICAL LEGAL THOUGHT: LAW AND IDEOLOGY IN AMERICA, 1886–1937, at 187 (1998).

45 Bates, *supra* note 43, at 31 (discussing Gifford Pinchot). Industry occasionally favored the progressive tendency toward federal authority, "sav[ing] them from the states." ROBERT H. WIEBE, BUSINESSMEN AND REFORM 202 (1962); *see also id*. at 212 (noting that "at least one segment of the business community supported each major program for federal control"). William Leach's fascinating history of the period proffers how "[t]he presence of the federal government in the lives of ordinary Americans was already manifest between 1895 and 1920," and after 1920 it acted "as a decisive agent in the making of the new American mass consumer economy and culture." LEACH, *supra* note 31, at 351.

46 *See* Robert S. Anderson, *The Lacey Act: America's Premier Weapon in the Fight Against Unlawful Wildlife Trafficking*, 16 PUB. LAND L. REV. 27 (1995). *See generally* MICHAEL J. BEAN, THE EVOLUTION OF NATIONAL WILDLIFE LAW 15 (1997). Congress also passed the Migratory Bird Treaty Act in 1918, effectuating a treaty with the United Kingdom. The Supreme Court during this period also upheld federal efforts to enforce cattle quarantine measures, under what today would be a cooperative federalism model with states. *See* Thornton v. United States, 271 U.S. 414, 425 (1926). The *Thornton* court found instructive *United States v. Ferger*, 250 U.S. 199 (1919), where the court sustained Congress' power to regulate bills of lading for interstate shipments. *See id*. at 205–06 ("As the power to regulate the instrumentality was coextensive with interstate commerce, so it must be, if the authority to regulate is not be denied, that the right to exert such authority for the purpose of guarding against the injury which would result from the making and use of spurious imitations of the instrumentality must be equally extensive.").

47 2 CHARLES WARREN, THE SUPREME COURT IN UNITED STATES HISTORY 736 (1926).

48 *See* Pub. L. No. 59-337, 34 Stat. 584 (1906).

49 *See* Pub. L. No. 61-218, 36 Stat. 539 (1910).

50 *See* Pub. L. No. 63-43, 38 Stat. 251 (1913).

Trade Commission Act in 1914,[51] along with a host other programs,[52] including the 1920 Transportation Act (building off the regulation of railroads).[53] It passed food and drug laws as well, affording uniformity in policy across jurisdictional lines; it promoted social welfare through statutes such as the Employers' Liability Act of 1906 (amended in 1908),[54] the Mann Act of 1910 prohibiting human trafficking when associated with prostitution,[55] the Keating-Owen Child Labor Bill prohibiting child labor in certain interstate activities,[56] and the Smith-Hughes Act of 1917 providing federal support for education.[57]

C. *Early Stages of Electric Energy Regulation*

Federal supervision over electric and natural gas infrastructure, however, lagged behind these other areas.[58] For

51 *See* Pub. L. No. 63-203, 38 Stat. 717 (1914). *See also* Fed. Trade Comm'n v. Gratz, 253 U.S. 421, 429, 432 (1920) (Brandeis, J., dissenting) (summarizing how the FTC developed to regulate competition and arrest undesirable aspects of consolidation).

52 *See, e.g.*, Meat Inspection and the Pure Food and Drug Act of 1906, Pub. L. No. 59-384, 34 Stat. 768.

53 *See* Dayton-Goose Creek Ry. Co. v. United States, 263 U.S. 456, 478 (1924); The New England Divisions Case, 261 U.S. 184, 189 (1923). The railroads had been nationalized during World War I, and with the 1920 act they once again were regulated under the Interstate Commerce Act. Introducing the bill, Senator Cummins observed how private ownership, "under strict public supervision," would be "better" and "cheaper" for the public. 3 BERNARD SCHWARTZ, THE ECONOMIC REGULATION OF BUSINESS AND INDUSTRY 1538 (1973).

54 *See* Pub. L. No. 59-239, 34 Stat. 232 (1906); Federal Employers' Liability Act, Pub. L. No. 60-100, 34 Stat. 65 (1908).

55 *See* White-Slave Traffic Act, Pub. L. No. 61-277, 36 Stat. 825 (1910).

56 *See* Pub. L. No. 64-249, 39 Stat. 675 (1916).

57 *See* Pub. L. No. 64-347, 39 Stat. 929 (1917). In 1917, Congress also passed the Food and Fuel Control Act, with the Fuel Administration created during WWI to address supply. *See* Pub. L. No. 65-41, 40 Stat. 276 (1917); *see also* Smith-Lever Act of 1914, Pub. L. No. 63-95, 38 Stat. 372 (establishing cooperative extension program).

58 Aside from waterpower, congressional interest focused principally on rights-of-ways through federal property. In 1896, Congress authorized granting various rights-of-way across public lands, including for electricity generation and transmission. *See* Act of May 14, 1896, ch. 179, 29 Stat. 120; Act of May 11, 1898, ch. 292, 30 Stat. 404 (amending the preceding act). In 1901, Congress expanded that authority, including through Yosemite and other national parks and forest reservations. *See* Act of Feb. 15, 1901, ch. 372, 31 Stat. 790. Land withdrawals for irrigation also provided the Interior Department with the authority to lease for ten years, affording preference to municipal purposes, "any surplus power or power privilege." Reclamation Act Amendments of 1911, Pub.

these two industries, attention generally gravitated toward state public utility commissions—establishing and avoiding confiscatory rates, as well as defining the role of the judiciary and developing workable legal rules for contracts, torts and property law as they affect the energy industry.[59] As a consumer advocate attorney, for instance, Louis Brandeis worked with Frederick W. Taylor, the father of "scientific management" in business, to illustrate how better efficiency in the utility industry could avoid increasing rates paid by the public.[60] Scientific management and its normative allegiance toward efficiency perhaps best captures the Progressive ethic.[61] Various reforms at the state commission level converged with an apparent interest in both utility commissions and the industry to explore uniform approaches toward the industry. Indeed, as one observer commented: "innumerable national, professional and trade organizations have

L. No. 61-417, 36 Stat. 930, 930 (albeit allowing up to a 50-year lease for the Rio Grande project in Texas and New Mexico). In 1911, Congress further afforded the Forest Service generic authority to grant easements for power development:

> That the head of the department having jurisdiction over the lands be, and he hereby is, authorized and empowered, under general regulations to be fixed by him, to grant an easement for rights of way, for a period not exceeding fifty years from the date of the issuance of such grant, over, across, and upon the public lands, national forests and reservations of the United States for electrical poles and lines for the transmission and distribution of electrical power, and for poles and lines for telephone and telegraph purposes . . .

Agriculture Department Apportions Act of 1911, Pub. L. No. 61-478, 36 Stat. 1235, 1253.

59 *See* JOHN DICKINSON, ADMINISTRATIVE JUSTICE AND THE SUPREMACY OF LAW IN THE UNITED STATES 156–202 (1927) (discussion of public utility regulation by leading scholar). An author of an early treatise on utility regulation and Harvard Law faculty member (until forced to resign for accepting money from a monopoly) explained how state supervision was the only viable option to the alternative of state ownership. *See* BRUCE WYMAN, THE SPECIAL LAW GOVERNING PUBLIC SERVICE CORPORATIONS AND ALL OTHERS ENGAGED IN PUBLIC EMPLOYMENT (1911).

60 *See* OLIVER ZUNZ, MAKING AMERICA CORPORATE 1870–1920, at 35 (1990). Zunz opines that Brandeis reflected that aspect of progressivism favoring "small against the mighty," "heterogeneity" over "homogenization," and "cultural pluralism." *Id*. at 36.

61 *See* HENRY F. MAY, THE END OF AMERICAN INNOCENCE 133–35 (1959) (describing Scientific Management's importance and acceptance by Justice Brandeis). *See also* SAMUEL HABER, EFFICIENCY AND UPLIFT: SCIENTIFIC MANAGEMENT IN THE PROGRESSIVE ERA 1899–1920, at 75–82, 95 (1964) (generally describing Taylor, Scientific Management, and Justice Brandeis' embrace).

unified the United States to much the same degree that the individual state was unified three decades ago."[62] The judiciary, however, as Herbert Hovenkamp persuasively argues, nevertheless struggled with emerging energy industries, trying to employ traditional legal doctrines to the new technology.[63]

Interest in electrical energy at the federal level centered principally on waterpower development and associated consolidation. During the first twenty years, in particular, Congress explored waterpower development on public lands and in the nation's waters. It passed the 1902 Reclamation Act and various other measures, including specific laws for particular projects.[64] The 1906 General Dam Act (amended in 1910), for example, required individual congressional assent for each project and established conditions for their development.[65] President Roosevelt eventually rejected this approach and instead urged that

62 Clarence M. Updegraff, *The Extension of Federal Regulation of Public Utilities*, 13 IOWA L. REV. 369, 370–71 (1928).

63 *See* HERBERT HOVENKAMP, ENTERPRISE AND AMERICAN LAW 1836–1937, at 114 (1991).

64 *See* JEROME G. KERWIN, FEDERAL WATER-POWER LEGISLATION 81, 85–89, 105–11, 129–30 (1926). *See also* MICHAEL C. ROBINSON, WATER FOR THE WEST: THE BUREAU OF RECLAMATION 1902–1977, at 9–18 (1979). Congress passed various rivers and harbors statutes, including in 1890 and 1899. *See* River and Harbor Act of 1890, ch. 907, 26 Stat. 426, 453–54; River and Harbor Appropriations Act of 1899, ch. 425, 30 Stat. 1121. In 1894, Congress allowed sales of power from irrigation projects, as well. *See* River and Harbor Act of 1894, ch. 299, 28 Stat. 338. Earlier statutes authorized water power development: In 1879, for instance, Congress provided for waterpower development by the Moline Water Power Company. *See* Act of March 3, 1879, ch. 182, 20 Stat. 377, 387. In 1884, Congress granted the Saint Cloud Water Power & Mill Co. the right to develop water power from the Mississippi River. *See* Act of July 5, 1884, ch. 231, 23 Stat. 154. In 1888, Congress authorized the Secretary of War to grant rights for waterpower development along the Muskingum River, Ohio. *See* River and Harbor Act of 1888, ch. 860, 25 Stat. 400, 417. And in 1890 Congress authorized granting waterpower privileges along the Green and Barron Rivers. *See* River and Harbor Act of 1890, 26 Stat. at 447.

65 *See* KERWIN, *supra* note 64, at 111–14. The 1906 Act, as interpreted by the Taft administration in an opinion by Attorney General Wickersham, did not permit charging a waterpower developer a fee for the use of the resources, prompting the amendment in 1910. *See* Charles K. McFarland, *The Federal Government and Water Power, 1901–1913*: *A Legislative Study in the Nascence of Regulation*, 42 LAND ECON. 441, 449 (1966). During this period, the battle over Hetch Hetchy and San Francisco's thirst for water and power emerged as the notable project precipitating widespread interest. *See generally* NORRIS HUNDLEY, JR., THE GREAT THIRST: CALIFORNIANS AND WATER, 1770s–1990s, at 169–90 (1992); ROBERT W. RIGHTER, THE BATTLE OVER HETCH HETCHY 117 (2005).

the nation assemble "the best experts available" to help plan the development of the nation's waterways.[66] Roosevelt tasked the Inland Waterways Commission with developing a comprehensive water resource plan, and consistently with his pledge to rely on experts he added to the Commission "a recognized authority on water power."[67] This became the signal effort to expand the "conservation" agenda beyond national forests.[68] The outcome was the symbolic birth of the "conservation" movement.[69] By 1908, the Progressive "conservation" community began actively exploring how to tap the nation's water resources without allowing private, monopolistic control.[70] A 1909 report by the Commissioner of Corporations to Roosevelt addressed concentration in the waterpower industry, and recommended governmental supervision

66 INLAND WATERWAYS COMM'N, PRELIMINARY REPORT, S. Doc. No. 60-325, at vi (1908).

67 *The Inland Waters Commission*, SCIENCE (June 26, 1908).

68 *See* JUDSON KING, THE CONSERVATION FIGHT: FROM THEODORE ROOSEVELT TO THE TENNESSEE VALLEY AUTHORITY 13 (1959). When delivering the interim report from the Commission he created a year earlier, President Roosevelt lamented how "the failure to use our own [rivers] is astonishing, and no thoughtful man can believe that it will last," adding that river systems need to be deployed to their "utmost"—with irrigation, power and water supply. He posited, in particular, how "[t]he use of water power will measurably relieve the drain upon our diminishing supplies of coal." INLAND WATERWAYS COMM'N, *supra* note 66, at iii–iv. He, therefore, encouraged Congress to establish an "administrative machinery for coordinating the work of the various Departments." *Id*. at v.

69 The Commission's effort led to a White House commission on conservation, and an accompanying call for a conference among the White House, governors and other significant political actors and policy makers (including members of the Supreme Court). Following the conference, the President appointed a National Conservation Commission tabbed with the responsibility of developing a report—a report that would soon be buried by Congress (and whose efforts would be succeeded by the National Conservation Association). *See generally* CHARLES R. VAN HISE, THE CONSERVATION OF NATURAL RESOURCES IN THE UNITED STATES 5–12 (1910); GIFFORD PINCHOT, BREAKING NEW GROUND 326–360 (1947); W. J. McGee, *The Conservation of Natural Resources*, *reprinted in* PROCEEDINGS OF THE MISSISSIPPI VALLEY HISTORICAL ASSOCIATION FOR THE YEAR 1909–1910, at 361, 374–5 (1910); THEODORE ROOSEVELT, THE NEW NATIONALISM 90–91 (1911).

70 New York's Governor, for instance, warned against allowing private, perpetual, control of the nation's resources. *See* KING, *supra* note 68, at 19–20. Progressives generally accepted that waterpower ought to be "controlled" rather than "owned" by "the public." *E.g*., VAN HISE, *supra* note 69, at 133–41. But several governors asserted states' rights when discussing control waterpower. *See Governors Uphold Rights of States*, N.Y. TIMES, Jan. 20, 1910, at 3 (describing addresses by Governor Hughes of New York, Governor Shafroth of Colorado, and Governor Brooks of Wyoming at the Conference of Governors).

over development but not of the electric rates from that development.[71] Wisconsin University President Charles Van Hise echoed the prevailing optimistic sentiment about how the nation's entire power requirements could be fed by waterpower—hindered only by the technical limits on constructing lengthy transmission lines.[72] In 1911, former President Roosevelt championed waterpower's importance and corresponding need for federal supervision rather than allowing state chartered monopolies.[73] A 1911 editorial in the magazine American Conservation reflected on the importance of waterpower and why the fight over governmental control had entered a "critical stage."[74] When the country elected Woodrow Wilson, "[w]aterpower development" had become "a matter of great concern to the whole country; it was before the public as it never had been."[75] And the concept of placing responsibility in a commission for supervising the development of waterpower was gaining currency.[76] This dialogue occurred amidst discussions about whether private interests or the federal government should tap the Tennessee Muscle Shoals for its nitrates and accompanying waterpower.[77] As waterpower

71 *See* Frederick P. Royce, *A Consideration of the Report of Commissioner of Corporations on Water Power Development of the United States*, STONE & WEBSTER 335–36 (May 1912). "This report generated great interest throughout the country and emphasized the need for a definite policy which remained a conspicuous proposal in 1912 just as in 1907 when Roosevelt created the Inland Waterways Commission." McFarland, *supra* note 65, at 450.

72 *See* VAN HISE, *supra* note 69, at 119–122, 136.

73 *See* ROOSEVELT, *supra* note 69, at 58–62, 95–99.

74 *Editorial*, 1 AM. CONSERVATION 193, 195 (July 1911).

75 KERWIN, *supra* note 64, at 171. *See also* COMM'R OF CORPS., *supra* note 36, at xv ("Within the last decade, through the development of electric transmission of power, our water-power resources have come into national importance."). This history is further documented in SAMUEL P. HAYS, CONSERVATION AND THE GOSPEL OF EFFICIENCY (1959), one of the most prominent books describing the conservation philosophy of the progressive era. *See also* Gifford Pinchot, *The Long Struggle for Effective Federal Water Power Legislation*, 14 GEO. WASH. L. REV. 9 (1945).

76 *See* KERWIN, *supra* note 64, at 204.

77 The Muscle Shoals debate mirrored the larger conversation about the utility of public versus private ownership and development, along with how best to plan for river development. *See* RICHARD RUDOLPH & SCOTT RIDLEY, POWER STRUGGLE 69 (1986) (describing how the Muscle Shoals "debate pitted defenders of public power against the private interests"). For other books describing the debate surrounding the controversy over federal development, *see generally* NORTH CALLAHAN, TVA: BRIDGE OVER TROUBLED WATERS (1980); PRESTON J. HUBBARD, ORIGINS OF TVA: THE MUSCLE SHOALS CONTROVERSY 1920–1932 (1961); C. HERMAN PRITCHETT, THE TENNESSEE VALLEY

development had by then become stymied,[78] a several-year dialogue ensued regarding whether water resources should be privately tapped or owned and controlled by the Federal government.[79]

In 1920, Congress resolved this policy choice by adopting the Federal Water Power Act (FWPA).[80] While congressional consideration earnestly began in 1916, Congress did not pass the FWPA until 1920, resolving the principal issues of payment, net investment and recapture, as well as the scope of waters subject to federal control. Importantly, the Act resolved a fight between private capital investment and federal ownership.[81] It deftly

AUTHORITY: A STUDY IN PUBLIC ADMINISTRATION 3–30 (1943).

78 *See* McFarland, *supra* note 65, at 451.

79 For a historical summary, see generally HAYS, *supra* note 75, at 73-81, 91-121, 160-64, 180-84; KERWIN, *supra* note 64; McFarland, *supra* note 65.

80 *See* Federal Water Power Act, ch. 285, 41 Stat. 1063 (1920) (codified as amended at 15 U.S.C. ch. 12 (2012)). Judson King describes some of the early troubles he was aware of plaguing the FPC. *See* KING, *supra* note 68, at 211–33. "The passage of the Water Power Act," nevertheless, "inaugurated [along with the Mineral Leasing Act of 1920] a new policy of continuing public ownership and federal trusteeship in which conservation and national interest seemed to be the winners." Bates, *supra* note 43, at 53. Also in 1920, the United States Geological Survey explored the possibility for a nationally-owned and controlled electric grid—opposed by the private sector—an idea followed three years later with a scaled down proposal from Secretary of Commerce Herbert Hoover; neither idea survived. *See* BRADLEY, *supra* note 20, at 175.

The FWPA, notably, occurred amid the Muscle Shoals controversy and conversations over whether the Federal government or private interests ought to develop the nation's water resources. *See* ROBERT K. MURRAY, THE HARDING ERA 412 (1969); *see also* PRITCHETT, *supra* note 77, at 4–11 (noting how the creation of the Tennessee Valley Authority began in 1916 with the "Muscle Shoals problem"). *See also* RIGHTER, *supra* note 65, at 167 ("Public-versus-private-power conflicts dominated the world of electricity for half a century."). Senator La Follette's third party presidential campaign advocated federal ownership of water resources, rather than monopoly-controlled private ownership. *See* 4 JOSEPH DORFMAN, THE ECONOMIC MIND IN AMERICAN CIVILIZATION 104–05 (1959). But as of 1920, waterpower development lagged when compared with coal, with the former roughly 7 percent of the latter. *See* GILBERT, *supra* note 36, at 166. A "contribut[ing]" reason for waterpower's retarded growth could have been "the inadequacies of Federal legislation," but other factors apparently were at play as well. *Id*. at 166–70, 178–79, 183, 236.

81 *See* MURRAY, *supra* note 80, at 412 (1969); *see also* NYE, *supra* note 20, at 183. "[E]nough public power companies remained" in the 1920s "to raise troubling questions about fair rates, democratic control, and public service that would be widely debated again in the 1930s." NYE, *supra* note 20, at 183. The authors of a 1921 report suggested the need for a common carrier obligation for electric transmission lines, which might induce and promote development. *See id*. at 236–40. *See generally* KERWIN, *supra* note 64, at 39–42 (discussing factors

avoided establishing jurisdictional lines for the sale and transmission of electric energy, when it modified the approach taken in the 1920 Transportation Act. There, Congress accepted the Supreme Court's holding in the *Shreveport Rate* case and allowed the Interstate Commerce Commission to regulate intrastate rates for transportation that affected interstate rates for transportation.[82] In the FWPA, by contrast, Congress allowed state public utility commissions the ability to regulate rates for sales of electricity in either intra- or interstate transactions.[83] Soon after Congress passed the FWPA, the FPC alluded to its ability, if necessary, to regulate rates for interstate sales, but saw "at the present time little probability that occasion for such action will arise."[84] Utilities had encouraged passage of the Act[85] and after its enactment responded favorably by submitting applications for preliminary permits.[86]

While the dialogue over waterpower raised the specter of monopolizing resources,[87] the electric industry was rapidly

purportedly arresting development).

82 *See* Esch-Cummins Act, Pub. L. No. 66-152, § 400, 41 Stat. 456, 474–75 (1920) (codified as amended in scattered sections of 49 U.S.C.); Houston E. & W. Tex. Ry. Co. v. United States, 234 U.S. 342, 349–59 (1914); GERALD BERK, ALTERNATIVE TRACKS: THE CONSTITUTION OF AMERICAN INDUSTRIAL ORDER, 1865–1917 (1997). *See generally* Paul S. Dempsey, *Transportation: A Legal History*, 30 TRANSP. L. J. 235 (2003).

83 Section 19 of the FWPA conditioned the issuance of a license upon the licensee's abiding by "reasonable regulation" of "any duly constituted agency of the State in which the service is rendered or the rate charged," and in Section 20 further provided "[t]hat when said power or any part thereof shall enter into interstate . . . commerce[,] the rates charged and the service rendered . . . shall be reasonable, nondiscriminatory, and just to the customer" and intimating acquiescence to state authority by adding the Federal Power Commission would have jurisdiction if no state agency exists for any state "directly concerned" to enforce the Act's proscriptions. §§ 19–20, 41 Stat. at 1073–74.

84 FED. POWER COMM'N, FIRST ANNUAL FPC REPORT 62–63 (1921).

85 *See* E. LOUISE PEFFER, THE CLOSING OF THE PUBLIC DOMAIN 120 (1951) ("The water-power question represented the most clear-cut example of the efforts by a major private interest to produce a law favorable to itself.").

86 By the close of 1920, the FPC had 143 applications. *See Water-Power Applications Filed in 1920, 13,000,000 Hp.*, 77 ELECTRICAL WORLD 138 (Jan. 15, 1921). Some states feared that the new act infringed states' rights. *See New York to Defend State's Rights in Water-Power Hearing*, 77 ELECTRICAL WORLD 169 (Jan. 15, 1921); *New York State Opens Fight on Water-Power Act*, 77 ELECTRICAL WORLD 219 (Jan. 15, 1921); *see generally* William H. Rose, *Control of Super-Power*, 80 U. PA. L. REV. 153, 171–73 (1931). *See also* KERWIN, *supra* note 64, at 290 (noting New York's withdrawal of its lawsuit).

87 In his 1908 message accompanying the interim report of the Inland

consolidating—coinciding with the national conversation over corporate capitalism and "bigness."[88] To be sure, consolidation and creation of holding companies helped secure capital investment and ensure sufficient electric generation capacity and a corresponding load. Arrangements with the electric or inter-urban trolley system (as Insull achieved with Chicago Edison[89]), for instance, guaranteed a ready market and a favorable load curve ensuring a consistent generation need. Consolidating ownership of facilities allowed companies the ability to generate sufficient capital for the large investments necessary to expand their systems and diversify their load for different patterns of use.[90] But public

Waterways Commission, President Roosevelt emphasized the evils of the "consolidation of companies controlling water power." INLAND WATERWAYS COMM'N, *supra* note 66, at V.

88 *See generally* GLENN PORTER, THE RISE OF BIG BUSINESS: 1860–1920 (2005) (discussing the growth of big business, the affect it had on society and markets, and the factors that prompted its growth); MARTIN J. SKLAR, THE CORPORATE RECONSTRUCTION OF AMERICAN CAPITALISM, 1890–1916 (1988) (describing what the author terms the "corporate reconstruction of capitalism," which facilitated the growth of big business during the Progressive era). Some, such as Louis Brandeis, simply opposed bigness, while others accepted concentration but thought its evils could be regulated by federal intervention. *See, e.g.*, Louis D. Brandeis, *An Illegal Trust Legalized*, 21 WORLD TODAY 1440 (1911), *reprinted in* THE CURSE OF BIGNESS: MISCELLANEOUS PAPERS OF LOUIS D. BRANDEIS 101 (Osmond K. Fraenkel ed. 1962). Brandeis shared his opposition toward bigness with progressive Wisconsin senator Robert La Follette. *See* MELVIN I. UROFSKY, LOUIS D. BRANDEIS: A LIFE 328 (2009).

89 *See* HUGHES, *supra* note 20, at 222–23 (noting importance of providing electricity to traction companies). Maury Klein explains how "[t]he streetcar business fit Insull's evolving business model for central stations perfectly. Trolleys swallowed huge amounts of power at the morning and evening rush hours, which fit neatly between the demand for lighting and factory power." KLEIN, *supra* note 20, at 418. The relationship of the utilities to the traction companies is part of the larger story about the growth of large holding companies, demonstrated by the Chicago Tribune's 1908 story *Traction Merger One Step Nearer*, CHI. TRIBUNE, Nov. 24, 1908 (noting proposed merger by Insull's company).

90 *See* RONALD SEAVOY, AN ECONOMIC HISTORY OF THE UNITED STATES FROM 1607 TO THE PRESENT 270–72 (2006); KERWIN, *supra* note 64, at 45–46 (Westinghouse and General Electric monopoly over waterpower). "The concern of many people over this concentration which in the early years of water-power activity was unregulated, and even now is not regulated altogether satisfactorily, was quite justifiable." KERWIN, *supra* note 64, at 56. A 1912 report highlighted the industry's considerable concentration. *See id*. at 156; *see also* COMM'R OF CORPS., *supra* note 36, at 9, 95–98 (explaining why concentration for waterpower may be different). Companies would own electric trollies, electric lighting companies, electric generating companies, and possibly natural gas companies. *See id*. at 166, 186 (e.g., Stone & Webster).

outcry questioned whether the electric transportation network and accompanying electric generation system should be in public or private ownership—or controlled by a select few.[91] And who should or could control these companies, whose financial situation was highly precarious and often beyond the reach of state regulation?[92] In 1925, the FTC began examining the problem with industry concentration, precipitating a more robust inquiry a few years later.[93]

As natural monopolies, however, holding companies could capitalize on the economies of scale, attract private capital, and correspondingly expand the electric grid.[94] As of 1922, there were

91 "A more comprehensive attack took place on those gas, light, and street-railway utilities which provided city services. Affecting intimately the lives of all urban citizens, the utility seemed to be an impersonal, greedy octopus . . . ." SAMUEL P. HAYS, THE RESPONSE TO INDUSTRIALISM 1885–1914, at 109 (1957). A nationally prominent organization's 1907 report concluded that, while public or private ownership should be determined by the local community, legalized monopolies with public regulation was warranted. *See* RUDOLPH, *supra* note 77, at 39. Writing in 1915, New York University Professor Benjamin P. DeWitt urged public or utility ownership of utilities as a component of progressivism. *See* BENJAMIN P. DEWITT, THE PROGRESSIVE MOVEMENT: A NON-PARTISAN, COMPREHENSIVE DISCUSSION OF CURRENT TENDENCIES IN AMERICAN POLITICS 352–57 (1915). According to Herbert Hovenkamp, this movement may have been hampered by existing theories of "ruinous competition" (rejected under the Sherman Act), if a franchise already had been awarded for the geographic area. HOVENKAMP, *supra* note 63, at 309–15.

92 *See* Nidhi Thakar, Note, *The Urge to Merge: A Look at the Repeal of the Public Utility Holding Company Act of 1935*, 12 LEWIS & CLARK L. REV. 903, 908–09 (2008).

93 *See* BRADLEY, *supra* note 20, at 176. The Preliminary Report from the Inland Waterways Commission emphasized the need for active federal and state regulation of the monopolization in the power sector. *See* KING, *supra* note 68, at 14. The FWPA generally prohibited "combinations, agreements, arrangements, or understandings, express or implied, to limit the output of electrical energy, to restrain trade, or to fix, maintain, or increase prices for electrical energy or service . . . ." Federal Water Power Act, § 10(h), ch. 285, 41 Stat. 1063, 1070 (1920) (codified as amended at 15 U.S.C. ch. 12 (2012)). By the mid-1990s, roughly 85 percent of the nation's electric generation was under the control of only 16 holding companies. *See* RUDOLPH, *supra* note 77, at 46. The concern escalated, leading to various committees and recommendations and ultimately the passage of the Public Utility Holding Company Act of 1935. *See generally* James W. Moeller, *Requiem for the Public Utility Holding Company Act of 1935: The "Old" Federalism and State Regulation of Inter-State Holding Companies*, 17 ENERGY L.J. 343, 357–58 (1996). The Act may have been "the most bitterly contested of the New Deal." Cudahy & Henderson, *supra* note 20, at 75.

94 *See* NYE, *supra* note 20, at 140. Governmentally owned electric systems (public power) began waning by the 1920s, and "[b]y 1932 . . . produced only

reportedly 3,774 privately owned electric systems and 2,581 municipally owned systems.[95] Between 1900 and 1934, the country's energy production rose from 2 billion kWhs to 90 billion kWhs.[96] Privately-owned utilities promoted Insull's view of minimal state regulatory oversight through public utility commissions. However, as they grew in organizational structure and infrastructure, achieving even greater economies of scale, these utilities naturally pushed the boundaries of effective state oversight.[97] Although the numbers may not be precise, one author suggests that by the time of *Attleboro* roughly "10.07 percent of the power produced for public consumption moved interstate."[98] And it was well understood at the time that the industry's growth was tied to an interconnected interstate grid.[99]

II. CONSTITUTIONAL NARRATIVE FOR EMERGING ENERGY MARKETS

The Supreme Court would need a constitutional narrative under the Commerce Clause for reviewing state regulation of this burgeoning business. That the court's idiosyncratic and unresolved constitutional narrative would surface for these newly evolving energy industries seemed pre-ordained with the Progressive imperative favoring the development of nation's water power.[100]

about 5 percent of the nation's electricity." *Id*. at 179–80.

95 *See* NAT'L ELEC. LIGHT ASS'N, POLITICAL OWNERSHIP AND THE ELECTRIC LIGHT AND POWER INDUSTRY 5 (1925). "Rural electric development," at the time, was arguably limited "under municipal ownership because communities are without authority to conduct any business or activities outside of their corporate limits." *Id.* at 21.

96 *See* Dozier A. DeVane, *Highlights of Legislative History of the Federal Power Act of 1935 and the Natural Gas Act of 1938*, 14 GEO. WASH. L. REV. 30 (1945).

97 *See* NYE, *supra* note 20, at 182–83.

98 DeVane, *supra* note 96, at 31. DeVane explains how some state commissions examined rates for power produced elsewhere or being shipped elsewhere. *See id.* (e.g. Maryland).

99 The interstate market comprised roughly 9% of total generation, and it was increasing dramatically. *See generally* William C. Scott, *State and Federal Control of Power Transmission as Affected by the Interstate Commerce Clause*, 14 PROC. ACAD. POL. SCI. 135 (1930). Overall, between just 1922 and 1930, total electric generation about doubled. *See* Cudahy & Henderson, *supra* note 20, at 55.

100 Benjamin P. DeWitt, for instance, quotes favorably a 1912 Report of the Secretary of the Interior that "[t]here is no more important subject now pending before Congress and the country than the adoption of a definite and comprehensive water-power policy." DEWITT, *supra* note 91, at 182. *See also* PINCHOT, *supra* note 69, at 334 ("The Government's problem, as we saw it, was

That narrative had been apparent for the railroad industry: two markets emerged, the short haul in-state service market and the interstate long-haul transport market, and state commissions promoted harmful economic rate discrimination favoring the former over the latter.[101] Therefore, when, Justice Brandeis reviewed Congress' ability to regulate intrastate railroad activities that affected the interstate market because of potentially discriminatory actions at the state level, he observed that

> Congress has power to assume not only some control, but paramount control, insofar as interstate commerce is involved. It may determine to what extent and in what manner intrastate service must be subordinated in order that interstate service may be adequately rendered. The power to make the determination inheres in the United States as an incident of its power over interstate commerce.[102]

The fact that Congress could or perhaps should act—a theme imbued throughout Progressivism,[103] did not resolve how far state jurisdiction would extend or whether both the states and Congress could share potential jurisdiction subject to Congress' preemptive authority.

The Supreme Court, however, generally disallowed concurrent jurisdiction if it deemed an activity as involving interstate commerce.[104] The court's analysis expanding the scope of federal power "also served to provide a boundary beyond which a state legislature might not go."[105] This occurred because the

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to ensure the fullest possible development of water power and its sale to the consumer at the cheapest possible price."). In 1910, Pinchot described "conservation of water power" as one of the most "pressing" "conservation" issues. GIFFORD PINCHOT, THE FIGHT FOR CONSERVATION 83 (1910). Theodore Roosevelt similarly commented about "[t]he enormous importance of water power sites to the future of industrial development." ROOSEVELT, *supra* note 70, at 58.

101 *See* HOVENKAMP, *supra* note 63, at 131–39.

102 Colorado v. United States, 271 U.S. 153, 165 (1926). *See also* R.R. Comm'n v. S. Pac. Co., 264 U.S. 331 (1924) (ability to regulate issuance of securities for interstate activities).

103 William Swindler posits that progressives sought to replace *laissez-faire* with "the need and opportunity for implementing a series of nationalistic laws." WILLIAM F. SWINDLER, COURT AND CONSTITUTION IN THE 20TH CENTURY 192 (1969).

104 *See generally* Sam Kalen, *Dormant Commerce Clause's Aging Burden*, 49 VAL. L. REV. 723 (2015).

105 WALTER F. PRATT JR., THE SUPREME COURT UNDER EDWARD DOUGLAS WHITE, 1910-1921, at 118 (1999).

court generally had treated those matters involving interstate commerce as exclusively within Congress' domain.[106] In 1925, the conservative Justice Van Devanter echoed the prevailing doctrine when he observed how states could "incidentally and remotely" affect interstate commerce for *permissible* reasons, but regardless of a state's motivation it could not "directly interfere[] with or burden[] such commerce."[107] A state could not, according to Van Devanter, impose certain burdens on foreign corporations doing business within a state, such as requiring that foreign corporations accept state (over federal) court jurisdiction as either a plaintiff or defendant.[108]

A. *Porous Lines*

In the transportation realm, the Supreme Court wrestled with the somewhat porous federal-state dividing line, allowing some state authority when the court perceived of it as a valid exercise of the police power but otherwise limiting the state's ability to regulate the interstate activity itself. In *Buck v. Kuykendall*,[109] for instance, Justice Brandeis invalidated a Washington State law that required a certificate of public convenience and necessity before a motor vehicle company could use the highways to transport passengers for hire. Washington denied Buck's request for a certificate on the grounds that the route was otherwise adequately served by other transportation means. Buck then claimed that Washington denied him his rights under the Fourteenth Amendment and that the program violated the Commerce Clause. Brandeis accepted that certain state measures would be permissible, if they were reasonably related to a legitimate state interest and avoided directly regulating interstate commerce.[110] But Washington's program addressed neither safety nor

106 *See* Hannibal & St. Joseph R.R. Co. v. Husen, 95 U.S. 465, 469 (1877).

107 Shafter v. Farmers' Grain Co., 268 U.S. 189, 199 (1925).

108 *See* Sioux Remedy Co. v. Cope, 235 U.S. 197, 204 (1914).

109 *See* 267 U.S. 307 (1925).

110 *See* 267 U.S. at 315. The court already had established that states could impose safety-related measures for interstate railroads. *E.g.*, Atl. Coast Line R.R. Co. v. Georgia, 234 U.S. 280 (1914) (headlights); Vandalia R.R. Co. v. Pub. Serv. Comm'n, 242 U.S. 255 (1916) (headlights on trains); Smith v. Alabama, 124 U.S. 465 (1888) (fitness of railroad engineer). *Cf.* S. Ry. Co. v. King, 217 U.S. 524, 539 (1910) (Holmes, J., dissenting) (suggesting that case dismissed on procedural grounds violated Commerce Clause because it might have impermissibly impeded interstate travel and the mails).

conservation; rather, it focused on competition in interstate travel—not just burdening but "obstruct[ing]" it contrary to Commerce Clause.[111] By contrast, a state could enforce traditional common law common carrier obligations on interstate carriers.[112] For the exploding automobile industry, the Supreme Court in *Hendrick v. Maryland*[113] established that states could require vehicle owners (even if they will travel in interstate commerce) to register and license their vehicles in the state. And a state could even deny a permit to travel along its roads if it reasonably concluded that additional traffic might cause a hazard—the exercise of a traditional or permissible police power.[114] Similarly, a state's police power—absent "national legislation"—extended to reasonable limitations on vehicle weight, even when those vehicles travelled in interstate commerce.[115]

An unacceptable exercise of the police power seemingly occurred if a measure appeared problematic under prevailing Fourteenth Amendment liberty and property doctrines. Indeed, the

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111 *Id*. at 316. *See also* George W. Bush & Sons Co. v. Maloy, 267 U.S. 317 (1925) (invalidating permit requirement for motor vehicle carrier). This same year the court upheld Congress' authority to pass the National Motor Vehicle Theft Act. *See* Brooks v. United States, 267 U.S. 432 (1925).

112 *See, e.g.*, Mo. Pac. R.R. Co. v. Larabee Flour Mills Co., 211 U.S. 612 (1909) (duty to serve local mill and transfer railroad cars, when serving others in the area). Justice Brown began one railroad case by observing how

> Few classes of cases have become more common of recent years than those wherein the police power of the state over the vehicles of interstate commerce has been drawn in question. That such power exists and will be enforced, notwithstanding the constitutional authority of Congress to regulate such commerce, is evident from the large number of cases in which we have sustained the validity of local laws designed to secure the safety and comfort of passengers, employees, persons crossing railway tracks, and adjacent property owners, as well as other regulations intended for the public good.

Cleveland, Cincinnati, Chi. & St. Louis Ry. Co. v. Illinois, 177 U.S. 514, 516 (1900).

113 *See* 235 U.S. 610 (1915). The court observed how such regulatory authority, unless preempted by Congress, was an essential aspect of traditional police power authority—albeit capable of being examined for its reasonableness. *See id*. at 622–23. *See also* Kane v. New Jersey, 242 U.S. 160 (1916) (following *Hendrick*, upholding New Jersey's licensing program).

114 *See* Bradley v. Pub. Utils. Comm'n, 289 U.S. 92 (1933) (Justice Brandeis upholding the denial of a certificate base on overly congested highway). In *Bradley*, *id*. at 95, Justice Brandeis referenced the Fourteenth Amendment case of *Stephenson v. Binford*, 287 U.S. 251 (1932), allowing a certificate of public convenience and necessity.

115 *See* Morris v. Duby, 274 U.S. 135 (1927).

loci of many cases otherwise involving interstate commerce centered on the Fourteenth Amendment and state and local actors' ability to regulate the price for commodities shipped in interstate commerce.[116] In *Michigan v. Duke*,[117] for instance, the state attempted to convert a private carrier traveling between states into a common carrier. This upset the carrier's existing contracts for hauling products, and imposed additional obligations, costs, and liability on the carrier without any justification for "public safety or order in the use of motor vehicles upon the highways, or to the collection of compensation for the use of the highways."[118] If an activity was affected with a public interest, quite possibly the jurisprudence would have allowed such an imposition[119]—but imposing it on highway traffic would have adversely altered the use and development of the nation's burgeoning transportation network. Absent treating the activity as affected with a public interest, the Supreme Court's precedent established that Michigan's measure violated the Fourteenth Amendment. A state, for instance, could not convert a private crude oil pipeline into a common carrier—under the Fourteenth Amendment, unless

> in the beginning or during its subsequent operation the pipe line was devoted by its owner to public use, and if the right thus extended to the public has not been withdrawn, there can be no doubt that the pipe line is a public utility and its owner a common carrier whose rates and practices are subject to public

116 *See, e.g.*, Williams v. Standard Oil Co., 278 U.S. 235 (1929). Judicial scrutiny of rates and probing whether a rate was confiscatory posed an imponderable dilemma for the court, particularly as the court delayed interring the doctrine from *Smyth v. Ames*, 169 U.S. 466 (1898). *See, e.g.*, Newark Nat. Gas & Fuel Co. v. City of Newark, 242 U.S. 405 (1917) (rates for sale of natural gas not confiscatory); Wilcox v. Consol. Gas Co., 212 U.S. 19 (1909) (whether natural gas rates confiscatory). *See* ALPHEUS THOMAS MASON, BRANDEIS: A FREE MAN'S LIFE 549 (1949) (noting that the doctrine was chaotic and "delusive").

117 *See* 266 U.S. 570 (1925).

118 *Id*. at 578. *See also* Smith v. Cahoon, 283 U.S. 553, 563 (1931) (certificate of public convenience and necessity and tax for *all* carriers "manifestly beyond the power of the state" under Fourteenth Amendment); Cont'l Baking Co. v. Woodring, 286 U.S. 352 (1932) (Kansas statute did not impose common carrier obligation on private carriers, and upheld reasonable license and fee requirements); Stephenson v. Binford, 287 U.S. 251, 271–72 (1932) (reviewing cases and concluding that statute at issue did not convert carrier into common carrier, and upholding Texas' purportedly reasonably related effort to address harm to its highways).

119 *See* Munn v. Illinois, 94 U.S. 113 (1876); *see also* Nebbia v. New York, 291 U.S. 502 (1934); New State Ice Co. v. Liebmann, 285 U.S. 262 (1932).

regulation.[120]

The court concluded, therefore, that Michigan's measure violated the Fourteenth Amendment, but then added how it also violated the Commerce Clause because the measure imposed an unjustifiable burden on interstate commerce.[121]

In a somewhat analogous context of regulating interstate transmission of telegraph messages, Justice Holmes had issued a seminal (though not necessarily analytically sound) opinion indicating that states were barred from regulating such transactions.[122] The state commission ordered that the telegraph companies (which provided the ticker services) refrain from engaging in discriminatory behavior when sending price quotations from the New York Stock Exchange. The telegraph companies had contracts with the Exchange, limiting ticker services to those brokers approved by the Exchange. The Exchange denied approval for ticker services to a Boston stockbroker, who had previously been served and sought approval from the Exchange to renew his service. Nothing suggested that the broker had done anything to warrant the Exchange's decision.[123] And prior cases already confronted the unique nature of the contracts between the Exchange and the telegraph companies.[124] Justice Holmes "reasoned" that, because the transmission was in interstate commerce,

> the order cannot be sustained. It is not like the requirement of some incidental convenience that can be afforded without seriously impeding the interstate work. It is an attempt to affect

120 Producers' Transp. Co. v. R.R. Comm'n, 251 U.S. 228, 230–31 (1920).

121 The reasoning seems terse. It simply announces that "[t]he police power does not extend so far." *Michigan*, 266 U.S. at 57. Justice Brandeis later invalidated a state measure imposed on bus companies—a business naturally open to the public. The measure did not distinguish between intrastate and interstate bus service, and Brandeis held the reasonable imposition did not violate the Fourteenth Amendment. *See* Sprout v. City of South Bend, 277 U.S. 163 (1928). Yet treating the Commerce Clause issue as more serious, he then carefully reviewed prior cases and, in characteristic fashion, examined the facts surrounding the imposition of a fee on the bus service, concluding that the license fee was not necessarily limited to intrastate activity and, as such, impermissibly taxed the privilege of engaging in interstate commerce. *See id*. at 171. *Compare id.*, *with* Bode v. Barrett, 344 U.S. 583, 585–86 (1953) (Justice Douglas, over the dissent of Justices Frankfurter and Jackson, distinguishing case from *Sprout*).

122 *See* W. Union Tel. Co. v. Foster (*Foster II*), 247 U.S. 105 (1918).

123 *See* W. Union Tel. Co. v. Foster (*Foster I*), 113 N.E. 192 (Mass. 1916).

124 *See, e.g.*, Tucker v. W. Union Tel. Co., 158 N.Y.S. 959 (Sup. Ct. 1915).

> in its very vitals the character of a business generically withdrawn from state control—to change the criteria by which customers are to be determined and so to change the business.[125]

Interstate commerce, according to Holmes, lasts until the article of commerce reaches its endpoint (derivative of the soon to be abandoned original package doctrine).[126] And then he added, without any explanation, that legitimate means could not be used for illegitimate ends, and that "[w]ithout going into further reasons we are of opinion that" the lower court's decision must be reversed.[127] Of course, the Massachusetts Supreme Court had avoided any meaningful discussion by concluding that the transmissions were neither part of interstate commerce nor governed by the Act of June 18, 1910, regarding interstate telegraph transmissions.[128]

B. *Natural Resources and Energy*

Additional wrinkles surfaced, however, when the Supreme Court confronted the distinction between permissible police power measures and impermissible restraints on interstate commerce involving state regulation of natural resources. "[I]t is difficult to define [the police power] with sharp precision. It is generally said to extend to making regulations promotive of domestic order, morals, health, and safety."[129] Contemporary scholars, for instance, debated whether a state enjoys an unfettered propriety interest in its natural resources within its borders, as well as whether the Commerce Clause imposes any restraint on the exercise of that power, assuming some proprietary interest.[130] After all, capacious state control over water resources posed

125 *Foster II*, 247 U.S. at 114.

126 *See id*. at 113.

127 *Id*. at 114.

128 *See Foster I*, 113 N.E. at 198. In *Hopkins v. United States*, 171 U.S. 578, 597–601 (1898), the court held that stock yard exchange transactions were not part of interstate commerce.

129 Hannibal & St. Joseph R.R. Co. v. Husen, 95 U.S. 465, 470–71 (1877).

130 *See* Dwight Williams, *The Power of the State to Control the Use of Its Natural Resources*, 11 MINN. L. REV. 129 (1926–27). Williams explains how, though a criticized fiction, the "theory had been developed by writers on natural law long before Blackstone" and embraced "not only wild animals but light, air, and water." *Id*. at 130. Courts generally embraced a theory that a state as a sovereign could protect such common resources in trust for its citizens. *See* State v. Rodman, 59 N.W. 1098 (Minn. 1894).

problematic issues for interstate ways.[131] But so did general game laws, where states sought to regulate hunting, fishing, and subsequent shipment of illegally obtained game or fish.[132] Professor Ernst Freund explained how history supported state control, but he doubted it would justify allowing greater freedom for preventing the export of game out of a state.[133] And this seemed implicit in *Greer v. Connecticut*,[134] where the Supreme

131 In 1903, water resource planner Elwood Mead wrote how "[i]t would seem that some sort of interstate regulation is required." ELWOOD MEAD, IRRIGATION INSTITUTIONS: A DISCUSSION OF THE ECONOMIC AND LEGAL QUESTIONS CREATED BY THE GROWTH OF IRRIGATED AGRICULTURE IN THE WEST 337 (1903) (describing the nascent fight between Colorado and Kansas). When New Jersey sought to restrict the ability of a riparian water right holder from transporting water from the Passaic River to New York, Justice Holmes averted an array of doctrines by engaging in a cursory discussion about the line between a permissible exercise of a state's police power and when that exercise renders property so valueless as to require compensation, and with *Greer v. Connecticut*, 161 U.S. 519 (1896), *Kansas v. Colorado*, 185 U.S. 125 (1902), and *Georgia v. Tennessee Copper Co*., 206 U.S. 230 (1907), as precedent, he observed how states enjoy quasi-sovereign (at one point called "omnipresent") interests in its resources and could protect those resources. *See* Hudson Cty. Water Co. v. McCarter, 209 U.S. 349, 356 (1908).

132 *See*, *e.g.*, *In re* Phoedovious, 170 P. 412 (Cal. 1918); Hornbeke v. White, 76 P. 926 (Colo. App. 1904); State v. Snowman, 46 A. 815 (Me. 1900); Stevens v. State, 43 A. 929 (Md. App. 1899); State v. Whitten, 37 A. 331 (Me. 1897); State v. Rodman, 59 N.W. 1098 (Minn. 1894); *In re* Maier, 37 P. 402 (Cal. 1894); Roth v. State, 37 N.E. 259 (Ohio 1894); Phelps v. Racey, 60 N.Y. 10 (1875); *cf*. Allen v. Wyckoff, 2 A. 659 (N.J. 1886); Moulton v. Libbey, 37 Me. 472 (1854). In *Hornbeke*, the Colorado court of appeals explained how the Supreme Court "laid down the principle that the state, in its sovereign capacity, has power to limit and qualify the ownership which a person may acquire in game with such conditions and restrictions as it may deem necessary for the public interest, and that there is a fundamental distinction between the ownership which one may acquire in game and the perfect nature of ownership in other property." 76 P. at 929. In *In re Maier*, the court avoided the Dormant Commerce Clause by observing how regulated meat that arrived in the state and removed from its original package became a commodity in the intrastate market. *See* 37 P. at 406.

133 *See* ERNST FREUND, THE POLICE POWER: PUBLIC POLICY AND CONSTITUTIONAL RIGHTS 445–46 (1904).

134 *See* 161 U.S. 519 (1896), *overruled by* Hughes v. Oklahoma, 441 U.S. 322 (1979). *Greer* first addresses the civil and common law background surrounding a sovereign's control over wildlife, *see id*. at 522–30, and then explains why game is not an article of commerce or if so not interstate commerce. *See id*. at 530–35. The court, in particular, found persuasive its precedent allowing states to prohibit selling alcohol. *See id*. at 532. Also, in Manchester v. Massachusetts, 139 U.S. 240, 265–66 (1891), the court had allowed state enforcement of a "reasonable" and "impartial" measure to protect fishery resources, unless otherwise regulated by the United States. Later,

Court upheld Connecticut's ability to prohibit the interstate shipment of lawfully obtained game. Oil and natural gas resource programs followed a similar path; states could protect such common resources against waste, and even regulate their production as a matter of local concern.[135]

Although many cases addressed somewhat vague Fourteenth Amendment claims,[136] the court wielded the Commerce Clause to prevent states from monopolizing oil and gas resources within their borders. Absent some check on state action, the emerging use of liquid fuels and accompanying transportation network could have been severely affected—at precisely the time when such fuels were competing with coal and becoming the basis for the nascent automobile industry. In *West v. Kansas Natural Gas Co.*,[137] for

however, the court made it abundantly clear that a state could not discriminate against interstate commerce by forcing interstate businesses to locate in the state in order to tap the state's natural resources. *See* Foster-Fountain Packing Co. v. Haydel, 278 U.S. 1 (1928) (examining the actual purpose animating Louisiana's Shrimp Act and invalidating Act). Where, however, the court found a state measure "reasonable," it had little trouble dispatching Dormant Commerce Clause and Fourteenth Amendment claims. *See, e.g.*, Leonard v. Earle, 279 U.S. 392 (1929) (Maryland's license fee for Oysters, including for those from out-of-state).

135 *See, e.g.*, Ohio Oil Co. v. Indiana, 177 U.S. 190 (1900). Here, Justice White rejected a claim that Indiana's program denied due process under the Fourteenth Amendment by taking private property. He explained how oil and gas could suffuse many surface estates and absent an ability for state control any owner choosing to capture the resource could waste the entire resource. *See id*. at 201. While White accepted some similarity between "animals *feroe naturoe* and the moving deposits of oil and natural gas, there is not an identity between them." *Id*. at 209. All, he posited, may potentially enjoy the common resource for the former, while only a limited set (surface owners overlying the resource) may enjoy the common resource for the latter. *See id*. at 209–10. Earlier, the court accepted as part of "common experience or knowledge" the unique "ownership" nature of oil and gas resources. Brown v. Spilman, 155 U.S. 665, 670 (1895); *see also* Ohio Oil Co. v. Indiana, 177 U.S. 190 (1900); *cf*. Lindsley v. Nat. Carbonic Gas Co., 220 U.S. 61 (1911) (statute protecting against waste of mineral waters and carbonic acid not violate Fourteenth Amendment). The court subsequently rejected a Fourteenth Amendment challenge to a state severance tax on production, if the tax and any distinctions were reasonable. *See* Ohio Oil Co. v. Conway, 281 U.S. 146, 160 (1930).

136 *See, e.g.*, Pierce Oil Corp. v. Hopkins, 264 U.S. 137 (1924) (claim that gasoline seller required to collect tax from purchaser using gas for vehicles on state highways violates due process clause).

137 *See* 221 U.S. 229 (1911). The statute purportedly operated as a conservation measure designed to arrest the large waste of gas occurring at the time; subsequent statutes made gas pipelines common carriers. *See* J. STANLEY CLARK, THE OIL CENTURY 160–61 (1958).

instance, the court invalidated Oklahoma's attempt to prohibit interstate transportation of natural gas produced in the state. While the court accepted some similarities with other resources such as wildlife, it held that a state would violate the Fourteenth Amendment if it denied all right to develop the resource; and here Oklahoma's purpose of creating a limited (in-state) market was unacceptable.[138]

The court, however, seemingly tolerated less intrusive rate regulation for petroleum and natural gas. It allowed state supervision over natural gas delivered by distributors to retail customers in the state, even if that gas arrived through interstate channels. In *Public Utilities Commission v. Landon*,[139] for example, the court applied Chief Justice Marshall's original package doctrine, a legal fiction, permitting a state's exercise of its police power once a product had come to rest in a state and been removed from its original package. And in *Pennsylvania Gas Co. v. Public Service Commission*,[140] it even upheld state regulation of

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138 According to the court,

> Gas, when reduced to possession, is a commodity; it belongs to the owner of the land, and, when reduced to possession, is his individual property, subject to sale by him, and may be a subject of intrastate commerce and interstate commerce. The statute of Oklahoma recognizes it to be a subject of intrastate commerce, but seeks to prohibit it from being the subject of interstate commerce, and this is the purpose of its conservation . . . commercial.

Kan. Nat. Gas Co., 221 U.S. at 255. Continuing, the court reflected its concern by adding how any other holding might allow hoarding of resources by resource-abundant regions. *See id*. *See also* Kan. Nat. Gas Co. v. Haskell, 172 F. 545, 572 (E.D. Okla. 1909) (statute conditioning ability to incorporate on keeping gas instate infringes on constitutional right, merging Commerce Clause and the Fourteenth Amendment). The *Kansas Natural Gas Co.* court's reasoning effectively protects what it believes was a federally protected right to engage in interstate commerce—beyond a state's domain for legitimate articles of commerce. *See* Kalen, *supra* note 104, at 750–63; *see also* Sam Kalen, *Reawakening the Dormant Commerce Clause in Its First Century*, 13 U. DAYTON L. REV. 417 (1988) [hereinafter Kalen, *Reawakening*].

139 *See* Pub. Utils. Comm'n Kan. v. Landon, 249 U.S. 236, 240, *vacated*, 249 U.S. 590 (1919).

See W. Oil Ref. Co. v. Lipscomb, 244 U.S. 346 (1917) (certain shipment of oil was not intended for state and mere stoppage did not break interstate character).

140 *See* 252 U.S. 23, 31 (1920) ("This local service is not of that character which requires general and uniform regulation of rates by congressional action," and even though "the business" being "conducted is part of interstate commerce, its regulation in the distribution of gas to the local consumers is required in the public interest and has not been attempted under the superior authority of Congress.").

natural gas sales delivered directly to local consumers when the gas moved in interstate commerce. But Justice Holmes, over a dissent joined by Justice Brandeis, effectively condemned a state's ability to tax petroleum produced in two different states and gathered together and shipped through an interstate pipeline.[141] Holmes reasoned that, because no party has title to any specific oil, and therefore its particular destination (in-state or out-of-state) is unknown,[142] it was beyond the state's reach. According to Holmes, the "transmission of this stream of oil was interstate commerce from the beginning of the flow" and, consequently, the tax was invalid.[143] Holmes' somewhat cryptic opinion and conception of the market ultimately would become problematic if applied to electric energy. It also would become problematic for Holmes, who was willing to afford considerable leeway to states when protecting resources for instate residents.[144]

This became evident two years later, when the Supreme Court resolved an original jurisdiction challenge by Pennsylvania and Ohio against West Virginia.[145] West Virginia, at the time, was the largest producer of natural gas and initially allowed foreign and domestic corporations to operate (and even exercise eminent domain authority) within its borders and ship gas through pipelines to markets in Pennsylvania and Ohio. As those markets developed, consumers grew dependent upon West Virginia's gas.[146] Indeed,

141 *See* Eureka Pipe Line Co. v. Hallanan, 257 U.S. 265, 272 (1921); U.S. Fuel Gas Co. v. Hallanan, 257 U.S. 277, 281 (1921). Holmes did not question West Virginia's ability to tax petroleum used in the state. The pipeline companies then generally kept the oil on behalf of the producers and would deliver oil to parties so designated by the producer (this was required under state law), in accordance with a tariff under the Interstate Commerce Act.

142 "No bailor has title to any specific oil, and to deny the character of interstate commerce to the whole stream simply because some one [sic] might have called for a delivery that probably would have been made from it in an event [sic] that did not happen, is going too far." *Eureka Pipe Line*, 257 U.S. at 272.

143 *Id*. The opinion contains little analysis, and Justice Clarke (joined by Justice Brandeis) discussed whether the Court should have even taken the case. The dissent further observed how Holmes had engaged in a "too highly technical conception," and inappropriately "allows the mere business convenience of the company (it saves storage tankage) to convert into interstate commerce that which all the parties, by their contract and conduct treated, and charged and paid for, as an intrastate transportation . . . ." *See id*. at 276 (Clarke, J., dissenting).

144 *See supra* note 132, and accompanying text.

145 *See* Pennsylvania v. West Virginia, 262 U.S. 553 (1923).

146 *See id*. at 585.

the court emphasized gas's importance for domestic consumption for schools and other users; the "health, comfort, and welfare" of the citizens seemed to be at risk.[147] But as demand began exceeding supply, not all states could enjoy the resource.[148] In 1919, West Virginia addressed the risk by passing a statute requiring "retention within the state of whatever gas may be required to meet the local needs for all purposes"—affording West Virginia citizens a preferential right to the perceived dwindling gas supply.[149] The neighboring states sued immediately, and while the court accepted the case and recognized its national importance,[150] it observed that precedent favored Ohio and Pennsylvania. Natural gas was an article of commerce, and West Virginia "serious[ly] interfere[red]" with its transmission in interstate commerce.[151] The court's earlier decisions in *West v. Kansas Natural Gas* and *Landon* made that clear.

Oddly, Justice Holmes, joined by Justice Brandeis, would have upheld the statute, reasoning that the act applied before the gas began moving in interstate commerce.[152] Holmes, in short, saw "nothing in the commerce clause to prevent a State from giving a preference to its inhabitants in the enjoyment of its natural advantages."[153] But Holmes' dissent aside, by the mid-1920s the

147 *Id*. at 592.

148 *See id*. at 589.

149 *Id*. at 594.

150 *See id*. at 595.

151 *Id*. at 597.

152 *See id*. at 600–01 (Holmes, J., dissenting), 605 (Brandeis, J., dissenting).

153 *Id*. at 602. Justice Brandeis analogized the suit to the original jurisdiction natural resource disputes (interstate water, interstate pollution) and suggested that, while they could be brought, this suit was premature. *See id*. at 605, 611–12 (Brandeis, J., dissenting). He also expressed concern about the court's capacity to award relief without exploring the regional dynamics of the gas market—something beyond the court's ken. *See id*. at 618–22. The case was closely divided, and possibly quickly decided to avoid losing Justice Day's vote who was about to retire. *See* ALPHEUS T. MASON, WILLIAM HOWARD TAFT: CHIEF JUSTICE 224 (1964). According to Brandeis, it also was poorly argued and garnered little interest from the bar—even though it was of national significance. *See* Letter from Louis Brandeis to Felix Frankfurter (Nov. 20, 1923), *in* 5 LETTERS OF LOUIS D. BRANDEIS 104–105 (Melvin I. Urofsky & David W. Levy eds., 1978). Yet Justice Day oddly wrote for a majority of the Court in *Hammer v. Dagenhart*, 247 U.S. 251 (1918), concluding that Congress could not prohibit articles manufactured with the aid of child labor and destined for an interstate market. According to Day, "the mere fact that they were intended for interstate commerce transportation does not make their production subject to federal control under the commerce clause." *Id*. at 271–72. And while Day did not object

law seemed clear—even if somewhat confusingly and inappropriately constructed: states could not interfere with the interstate shipment of natural gas; rather, they could only regulate local sales. In *Missouri ex rel. Barrett v. Kansas Natural Gas Co.*,[154] therefore, the court explained how retail sales to consumers were local—as if the interstate article had come to rest in the state and could be regulated, but until then the wholesale transactions in interstate commerce were of a national character. For the emerging interstate gas market, while this made state regulation difficult, it was seemingly workable because the court tolerated the authority of a state commission to force a company to continue servicing a local community from gas produced in the state even though the gas was comingled with gas transported from another state in interstate pipelines and sold both to local consumers and to a local distribution company.[155] But as the Supreme Court recently observed, these cases precluded a host exporting state from regulating the sale of gas to an out-of-state local distributor for resale, eventually prompting the passage of the Natural Gas Act.[156]

III. THE INTERSTATE GRID AND A RATE INCREASE?

A notorious northeastern electric utility precipitously forced the Supreme Court to apply this unsettled constitutional narrative to state electric utility regulation. By the time the court decided *Attleboro*, electricity had become the foundation for the new consumer economy. It transformed cities through the formation of city-dominated factories, lighting, and electric trollies, among other things. It also generally helped lift the country out of its pre-World War I depression.[157] The electric utility industry,

to Congress' authority to regulate wages for interstate railway employees, he did object to its regulation as a violation of due process. *See* Wilson v. New, 243 U.S. 332, 365–66 (1917) (Day, J., dissenting).

154 *See* 265 U.S. 298, 309 (1924).

155 *See* People's Nat. Gas Co. v. Pub. Serv. Comm'n, 270 U.S. 550 (1926). The court accepted that the comingled gas was "separable," with the percentages of local and out-of-state gas identifiable. *Id*. at 554–55.

156 *See* Oneok, Inc. v. Learjet, Inc., 135 S. Ct. 1591 (2015).

157 *See generally* JEFFRY A. FRIEDEN, GLOBAL CAPITALISM: ITS FALL AND RISE IN THE TWENTIETH CENTURY 143–47 (2006). Frieden hints how electricity furnished the basis for the new consumer economy, with household goods as well as factories—such as those that would build the Model T—dependent upon electricity. *See id*. at 157–59. *See also* DAVID E. NYE, CONSUMING POWER 157–85 (1998). By 1923, there were 102 central-station corporations or public agencies" generating "in excess of a hundred million kilowatt hours each of

particularly in the Northeast, wrestled with how to interconnect transmission systems, whether and how states could control their own natural water resources for waterpower development, and whether state public utility commissions were capable of regulating an expanding grid. The utility trade association as well as the FPC understood how actors in the unfolding utility industry, including the utility commissions, would need to develop uniform standards.[158] The FPC, for instance, commented on the need for a "settled public policy of uniform application" for the industry, not just with hydroelectric generation, and that such a policy should embrace "harmonious action between the Nation and the States and between State and State."[159] This would mean that state utility commissioners ought to be appointed for their expertise rather than "political affiliations," and states ought not to erect barriers to the interchange of electricity.[160]

An interconnected system seemed particularly necessary in the northeast and the idea of a superpower surfaced.[161] When WWI ended, railroad bottlenecks, coal strikes, capital markets, as well as the 1920 FWPA and other influences prompted electric utilities to explore new arrangements for interconnecting grids—or regional

electric energy." 4 FED. POWER COMM'N ANN. REP. 14 (1924).

158 In 1921, the president of the National Electric Light Association told his members that, while utilities "are vitally essential to the industrial world," they must secure "the co-operation of the public and the unanimous support of the other branches of the industry." Martin J. Insull, *The Electric Public Utility Outlook*, 77 ELECTRICAL WORLD 3 (Jan. 21, 1921).

159 3 FED. POWER COMM'N ANN. REP. 8 (1923).

160 *Id*. at 9. The Commission further observed:

> State interests must, nevertheless, be harmonized in a policy and program which will be to the common interests of them all. This will require cooperative action and reasonable uniformity of legislation. There must be no State barriers against the interchange of energy, and no type of development that can not [sic] become an integral operating part of the combined system. Legislation which interferes with the programs should be repealed or modified; necessary affirmative legislation should be had; public officials of both State and Nation should lend the program their support; and, finally the industry itself should harmonize its own conflicting interests. It should no longer be permissible for any utility to draw plans for future extension except in such manner that interconnections may be readily effected whenever its territory merges with the territory of any other utility.

Id. at 9–10.

161 Of course, Insull too favored a superpower in the Midwest. *See* WASIK, *supra* note 20, at 136–37.

systems.[162] One prominent idea was establishing a supergrid in the Northeast.[163] The region between New England and the nation's capital explored developing a "superpower" utility—an interconnected, "regional power system with which to generate, transmit and distribute electrical energy to the railroads and industries within" its territory.[164] Utilities at the time appreciated the need to cooperate in interconnecting and delivering energy in an efficient manner.[165] Herbert Hoover delivered a speech to the National Electric Light convention in April 1922, urging the merits of a coordinated approach toward power supply—but the idea languished as New York and Pennsylvania's governors were more concerned about public rather than private ownership of power generation.[166] A participant in the development of the Colorado River Company, Hoover in 1923 again encouraged that utilities cooperatively develop "uniform principles and policies for 'coordinated State regulation.'"[167] He repeated this again a few years later, adding that states enjoyed sufficient regulatory ability

162 *See* RONALD SEAVOY, AN ECONOMIC HISTORY OF THE UNITED STATES FROM 1607 TO THE PRESENT 268, 274 (2006) (regional systems under construction in the 1920s).

163 *See* KENDRICK A. CLEMENTS, THE LIFE OF HERBERT HOOVER 257 (2010).

164 W.S. Murray, *Superpower Investigation Between Boston and Washington*, 77 ELECTRICAL WORLD 27 (Jan. 1, 1921). Murray supervised the Department of the Interior's report on the superpower system. *See* Felix Frankfurter & James M. Landis, *The Compact Clause of the Constitution—A Study in Interstate Adjustments*, 34 YALE L. J. 685, 709 n.98 (1925).

165 "In these days of team play among public utilities the subject of interconnection rises to large importance . . . as a policy to be followed whenever feasible." *Effective Interconnection Requires Team Play*, 77 ELECTRICAL WORLD 186 (Jan. 15, 1921); *see also* A.T. Throop, *Improvement of Interconnection by Liberal Co-operation*, 77 ELECTRICAL WORLD 202 (Jan. 15, 1921). Engineering, however, was not considered a barrier for a superpower, but rather—along with financial considerations—the need to overcome some state corporation laws by establishing a federally chartered company that would be supervised by state utility commissions. *See Second General and Executive Session: Samuel Insull and James A. Perry Make Notable Addresses—Superpower Survey Discussed—Reports of Rate Research and Lamp Committees*, 77 ELECTRICAL WORLD 1287 (June 4, 1921).

166 *See* CLEMENTS, *supra* note 163, at 257. Hoover had been the "chairman of the Northeastern Super Power Committee, composed of federal officials, and the chairman of public utility commissions of ten northeastern states," with the mission of "interconnecting all the private companies in these states and thus secure to them the financial benefits of an integrated 'superpower system' extending from Boston to Washington." KING, *supra* note 68, at 142; *see also id.* at 167.

167 CLEMENTS, *supra* note 163, at 257.

to oversee the industry.[168] Such coordinated, interconnected efforts were becoming technologically more feasible with the advent of high power 220kv transmission lines.[169] The FPC that same year noted how "[t]here has been much discussion in recent years of the subject of 'superpower'."[170] Indeed, the FPC observed that a considerable portion of the Pacific already had been interconnected with the exception of a 25 mile gap; that the Southeast too had been interconnected; and that the features of the Northeast to Mid-Atlantic were appropriate for a similar endeavor.[171]

The superpower concept garnered sufficient attention that the prominent 1925 article by Felix Frankfurter and James Landis included a lengthy discussion about the role of compacts for future energy development.[172] Their article explored the superpower dialogue and encouraged putting the electric utility industry under some federal control analogous to the Interstate Commerce Commission.[173] The initial question posed was not whether states could act (or enter into interstate compacts), but rather whether states enjoyed exclusive authority to regulate the industry.[174]

168 *See* WASIK, *supra* note 20, at 149–50.

169 *See Power Transmission at 220,000 Volts*, 77 ELECTRIC WORLD 74 (Jan. 8, 1921) ("Transmission at 220,000 volts will be brought into the realm of actuality at a very near date."). *See also* Clinton Jones, *Building First 220,000-Volt Transformers*, 77 ELECTRICAL WORLD 301 (Feb. 5, 1921).

170 3 FED. POWER COMM'N ANN. REP. 5 (1923). The Commission defined a superpower as "existing generating stations . . . electrically interconnected to a greater degree than now prevails and that, whether as additions to existing facilities or as substitutes for what has become obsolete or inadequate, new stations when built shall be of large size and high efficiency." *Id*. at 6. Participants acknowledged unresolved legal issues, such as whether state created charters or a federal charter would be necessary. *See Murray Declares Superpower System Must Have Adequate Return*, 77 ELECTRICAL WORLD 220 (Jan. 22, 1921).

171 *See id*. at 6. The considerable investment required for large hydroelectric projects, as well as the ability to supplement other forms of generation, made interconnecting essential. *See id*. at 7.

172 *See* Frankfurter & Landis, *supra* note 164, at 708–18.

173 *See id*. at 711–12.

174 *See id*. at 713–14. They referenced several cases allowing state regulation of resources that would move in interstate commerce. *See, e.g.*, United Mine Workers of America v. Coronado Coal Co., 259 U.S. 344, 410–11 (1922) ("[C]oal mining is not interstate commerce, and obstruction of coal mining, though it may prevent coal from going into interstate commerce, is not a restrain of that commerce, unless the obstruction to mining is intended to restrain commerce in it, or has necessarily such a direct, material, and substantial effect to restrain it . . . ."); Heisler v. Thomas Colliery Co., 260 U.S. 245, 259 (1922) (coal tax); Oliver Iron Mining Co. v. Lord, 262 U.S. 172 (1923) (state occupation

While rejecting any suggestion that Congress could not act, they instead proposed an "interstate arrangement,"[175] and eloquently added:

> The frequent resort in recent years to the Commerce Clause as a source of regulatory power by Congress, has blurred its historic purpose and its continued use as a veto power on obstructive and discriminatory State action. It is a reservoir of Federal power and not a dam against State action.[176]

A. *Utility Commission Changes a Contractual Rate*

The failure to develop a uniform system or superpower permitted one of the largest loads in the Northeast, served by the Narragansett Electric Light Company (Narragansett) and aided by the Rhode Island Public Utility Commission (R.I. PUC), to test that dam and presumably how far a state utility commission might favor local residents over out-of-state electric needs. At the time, Providence was the second largest load center in New England, with about 58% of the load of Boston,[177] and Narragansett was one of the largest utilities, chartered by Rhode Island in 1884 and originally engaging in business solely within the state. With Marsden Perry at its helm, Narragansett grew as a multi-faceted company controlling a large portion of the state's electric lighting, gas lighting, water service, and electric streetcar service. With political assistance, it secured the necessary long-term exclusive (monopoly) franchise to provide service. The streetcar service secured a "'perpetual' franchise . . . to replace the old-twenty-to-twenty-five year franchises" and with power being supplied from

tax on mining for mostly out-of-state customers); United Leather Workers' Int'l Union v. Herkert & Neisel Trunk Co., 265 U.S. 457, 625 (1924) (following *Coronado* for striking against business in leather goods and trunks). Notably, Frankfurter and Landis apparently favored Maine's ability to prevent the exportation of any hydroelectric generation, as an effort in "experimentation" and designed to conserve "precious resources within their borders." Frankfurter & Landis, *supra* note 164, at 716. Proponents of the superpower were aware of Maine's prohibition, as well as Connecticut's ban against imported waterpower, and believed that a federally chartered corporation could resolve the legal constraint. *See Legal and Financial Aspects of Superpower Plan*, 77 ELECTRICAL WORLD 1156 (May 21, 1921) (comments by the president of the New England Power Company).

175 Frankfurter & Landis, *supra* note 164, at 714–18.

176 *Id*. at 719.

177 *See* MURRAY ET AL., *supra* note 38, at 32.

the electric company it seemingly had an assured market.[178] By controlling all these entities, Perry became "the state's utility king."[179] Although Perry was long gone, the company by the 1920s was undoubtedly well known and remained mercurial as it considered whether to join the New England Power System.[180] After all, it was under Perry's leadership when, in 1902, the nation witnessed one of its more prominent strikes—with Perry refusing to abide by the newly passed 10-hour work law.[181] And it was under Perry and others (including Rhode Island's powerful Senator Nelson W. Aldrich) when muckraker Lincoln Steffens focused national attention on the holding company's control over the state's utility system: writing for *McClure's Magazine* in 1905, Steffens exposed how the electric utility and street railway curried political favoritism and insulation.[182]

Thus, it is not surprising that the R.I. PUC obliged when Narragansett sought a rate increase affecting its only out-of-state customer. It is quite exceptional, however, that prevailing constitutional dogma on the Commerce Clause would envelop the dispute. The case, after all, involved the evolving authority of a public utility commission to alter a contractual rate when it determines that the rate has become discriminatory. It was a "minor" quibble, and "no one expected that it would result in an important ruling."[183] Attleboro Steam and Electric Co. (Attleboro),

178 WILLIAM G. MCLOUGHLIN, RHODE ISLAND: A HISTORY 177–79 (1986). *See also Narragansett Co. Would Acquire United Railway*, HARTFORD COURANT, Sept. 10, 1926, at 19 (noting that long-term agreement to provide electricity to trolley line).

179 SCOTT MOLLY, TROLLEY WARS 67 (1996). Molly provides a fascinating account of the dynamics surrounding the railroads, traction companies, and the utilities, and political influence. *See generally id.*

180 *See Narragansett Not In Power Merger*, CHRISTIAN SCI. MONITOR, Jan. 19, 1926, at 4B. *See also R.I. Utility Merger is Still Under Discussion*, HARTFORD COURANT, Aug. 14, 1926, at 5 ("Evidently the great majority of the stockholders desire the Narragansett Electric Lighting Company to continue as an independent organization, free from outside control.").

181 *See* MOLLY, *supra* note 179, at 131–51.

182 *See* Lincoln Steffens, *Rhode Island: A State for Sale*, 24 MCCLURE'S MAG. 337 (1905). Steffens wrote how this group "conceived and carried to success a scheme to buy up, equip with electricity, and not only run, but finance, the hold horse-car lines of Providence, Pawtucket, and later, of the State." *Id*. at 347. The scheme ultimately morphed into consolidating all the utilities "into one great parcel, 'The Rhode Island Company,'" with exclusive and effectively long-term franchises. *Id*. at 248.

183 *Federal Control of Power Forecast*, NEW YORK TIMES, Jan. 16, 1927, at

a Massachusetts based utility, had contracted in 1917 with Narragansett (with R.I. PUC approval) to purchase electricity for twenty years at a fixed rate with a transfer of "ownership" at the state line. Seekonk Co., as an agent for Attleboro, would transmit the electricity from the Massachusetts state line to Attleboro's lines.[184]

World War I changed the economics of the Narragansett/Attleboro contract and made the rates for electricity being sold to Attleboro uneconomic and lower than Narragansett's rates for Rhode Island customers.[185] Indeed, "[b]y 1923 Rhode Island was a bitterly divided state, socially, economically, and politically," with a considerable portion of its dominant textile industry unable to compete with the South's industry.[186] Narragansett understandably requested that the Rhode Island PUC approve a new rate schedule. Created in 1912, the Rhode Island PUC enjoyed the typical authority to establish just and reasonable rates if it determined that a rate is unjust, unreasonable, insufficient, or unjustly discriminatory or preferential. While Attleboro protested, it did not otherwise present information and subsequently "refused to pay the new rate" and filed a lawsuit to enjoin the application of the new rate.[187] Attleboro warned that it lacked sufficient access to electrical generation and absent energy from Narragansett "the City of Attleboro would be deprived of electrical energy and power to . . . incalculable damage" to itself and the city's residents.[188] This, according to Attleboro, was particularly unfair because Narragansett had convinced Attleboro

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184 Narragansett delivered the electricity at the state line between the town of Seekonk, Massachusetts, and the town of East Providence, Massachusetts, and it was metered by Attleboro in Massachusetts. Transcript of Record, at 258, Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927) (No. 217).

185 Transcript of Record at 59, 111, 120–21, Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927) (No. 217).

186 MCLOUGHLIN, *supra* note 178, at 191; *see also id*. at 195–96. In 1921, however, Narragansett Electric's use of more oil than coal apparently saved the company money and strengthened its financial outlook for future years. *Narragansett Company Saves $362,000 by Use of Oil as Fuel*, 77 ELECTRICAL WORLD 503 (Feb. 26, 1921).

187 Petition for Writ of Certiorari at 3, *Attleboro*, 273 U.S. 83 (No. 217).

188 Attleboro Steam & Elec. Co. v. Narragansett Elec. Lighting Co., 295 F. 895, 896 (D.R.I. 1924). Indeed, Attleboro "*dismantled* and *removed* their own generating plant in reliance on th[e] contract." Transcript of Record at 117, *Attleboro*, 273 U.S. 83 (No. 217) (emphasis added).

to enter into the contract rather than to construct its own additional generation.[189] After a district court enjoined the PUC's action, effectively on procedural grounds,[190] Attleboro's counsel informed the PUC that it believed that its contract with Narragansett could not, in effect, be abrogated,[191] and that the Commission lacked jurisdiction because the *contract* involved interstate commerce, and that the courts would need to decide the matter—intimating that it was not clear whether the Commission could entertain the issue.[192] Attleboro's invocation of the Commerce Clause presumably could have been deployed as its principal mechanism for avoiding a fair consideration of its rate dispute with Narragansett—which otherwise would be a state rather than federal issue, unless it could argue that the abrogation of the

189 *See* Transcript of Record at 189–90, *Attleboro*, 273 U.S. 83 (No. 217). Attleboro's need for generation had increased, and according to news reports, would have cost the company $630,000 to build. It became efficient, therefore, to connect with Narragansett's system and build a new 12-mile transmission line (operated by the Seekonk Electric Company) for transmitting the power. *See Typical Benefits from Plant Interconnection*, 71 ELECTRICAL WORLD 449 (Mar. 2, 1918). Narragansett lacked authority to construct facilities in Massachusetts and its contract with Attleboro addressed the allocation of costs and agreement with Seekonk. *See* Transcript of Record at 253, *Attleboro*, 273 U.S. 83 (No. 217). At the hearing, Attleboro's counsel suggested that Narragansett's rate increase was to recover some of Narragansett's costs for building that line. *See* Transcript of Record at 203, *Attleboro*, 273 U.S. 83 (No. 217).

190 *See Narragansett*, 295 F. at 895. A report about the case noted that the PUC even permitted the rate to go into effect immediately, "without the statutory notice of thirty days." *See Increase in Contract Rate Between Companies Authorized*, 77 ELECTRICAL WORLD 1184 (May 21, 1921).

191 *See* Transcript of Record at 195–98, *Attleboro*, 273 U.S. 83 (No. 217). Indeed, Narragansett complained how Attleboro used its contract price as a shield rather than accepting negotiating a modified rate, prompting the dispute. *See id*. at 213. The *Boston Globe* reported how, apparently, Narragansett offered to alter the rate to increase the annual cost by only $20,000, which met with "indignation." *Rate Case Is Won by Attleboro Firm*, BOS. GLOBE, Jan. 4, 1927, at 14. At the hearing, Attleboro's motion argued that "as a matter of constitutional law and as a matter of statutory construction, that the contract of 1917 cannot be abrogated." Transcript of Record at 350, *Attleboro*, 273 U.S. 83 (No. 217).

192 *See* Transcript of Record, at 36–37, *Attleboro*, 273 U.S. 83 (No. 217); *see also id.* at 151 (counsel objected on the record to PUC's jurisdiction). Counsel's first argument was that PUC lacked statutory authority, because law only applied to in-state public utilities. *See id*. at 157. The PUC responded by observing:

> We feel that our jurisdiction extends to all of the practices of the utility there which is within our jurisdiction. If we assumed any other position, why, these utilities might furnish electricity outside the State, completely outside our jurisdiction and out of any one's else jurisdiction.

Id. at 163.

contract violated the Contract Clause or the Fourteenth Amendment.

The Rhode Island PUC nevertheless proceeded and engaged in a more robust proceeding, concluding that Narragansett was likely to have a net loss of about $1.5 million over the life of the contract. Yet Attleboro's counsel argued that Narragansett was trying to shift its new capital costs onto Attleboro because Narragansett's only other large (indeed largest) customer was New England Power Company and it could not determine how much fixed costs it could impose on that company.[193] Narragansett's proposal would force Attleboro to pay about an additional $50,000 annually.[194] The PUC's new rate ostensibly still afforded Attleboro a reliable source of electricity at a cost below Attleboro's own cost of operation. Attleboro objected and filed a challenge before the Rhode Island Supreme Court, attacking the order as well as the PUC Act itself, claiming that it deprived the company of its property without due process, denied it equal protection of the laws, impaired its contractual relationship, and impermissibly "interfer[ed] with interstate commerce."[195] The Rhode Island Supreme Court avoided the principal issue of whether or when it could alter a contractually established rate, opting instead to address the latter argument and finding the principles of *Missouri v. Kansas Natural Gas Co.*[196] dispositive—concluding the state's

193 At the hearing, Attleboro's counsel believed that Narragansett had sought higher rates because (1) it failed to distinguish between a wholesale and retailer purchaser; (2) had added to its plants to serve New England Power Co. (receiving roughly 50% of its energy through other entities, whether Atlantic Power Company or R.I. Power Transmission); and (3) that the new proposed rate would apply primarily if not exclusively to Attleboro. The difficulty, apparently, was that Narragansett could not calculate how much energy it sold as an interruptible service (called "secondary" current) to New England Power and secondary energy would not include a demand or capacity charge as part of the rate (e.g., not charge New England Power for cost of capital assets). Narragansett's original 1917 rate may not have included a sufficient demand charge, and the capital costs since the war allegedly doubled. *See* Transcript of Record at 111–12, *Attleboro*, 273 U.S. 83 (No. 217). And Attleboro's counsel secured an admission from Narragansett's witness that it would not need "$50,000 more from the Attleboro Company to make" it "a successful company with dividends reasonably assured on reasonable rates charged to" its customers. *Id.* at 104.

194 *Id.* at 189.

195 Petition for Writ of Certiorari at 8, *Attleboro*, 273 U.S. 83 (No. 217).

196 *See* 265 U.S. 298 (1924). *Cf.* Mfrs' Light & Heat Co. v. Ott, 215 F. 940, 945 (N.D. W. Va. 1914) (reasonable rate regulation a local matter unless a state attempted to "prevent the transportation and sale of natural gas from" one state to

action amounted to an impermissible "direct" burden on interstate commerce, regardless of purpose. And from that decision, the Rhode Island Attorney General initiated the U.S. Supreme Court's review.

That the case provoked a legitimate Commerce Clause issue seemed peculiar under the Supreme Court's precedent. Almost all state jurisdiction might be usurped if, for example, states were precluded completely from regulating goods produced in their state. Some of those goods might be destined for interstate markets, or perhaps not. While possibly a Fourteenth Amendment claim, nothing suggested that the Commerce Clause would block a state from regulating products that eventually would move in interstate commerce.[197] Also, the court previously had placed manufacturing within the states' realm and outside the Commerce Clause.[198] It would be cumbersome to explore on a case-by-case basis the likely movement of products. Assuming theoretical lines could be erected for distinguishing between goods likely to remain in the state and those marked for interstate markets, producers naturally might favor escaping regulation by tilting toward out-of-state sales—effectively discriminating against intrastate markets. This occurred many decades later when the court oddly gave the FPC rather than states jurisdiction over natural gas production and gathering for gas intended for interstate markets.[199] The court by this time also had permitted states and the federal government to share spheres of jurisdiction—albeit subject to Congress' paramount power.[200]

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another).

197 *See supra* note 174. The Supreme Court even had prevented Congress from regulating goods before they entered commerce. In *Hammer v. Dagenhart*, 247 U.S. 251, 272 (1918), for instance, Justice Day famously wrote that "[o]ver interstate transportation, or its incidents, the regulatory power of Congress is ample, but the production of articles, intended for interstate commerce is a matter of local regulation." *See also* Heisler v. Thomas Colliery Co., 260 U.S. 245, 259 (1922) (noting that "a tax upon articles in one state that are destined for use in another state cannot be called a regulation of interstate commerce"). Also, in *Coe v. Town of Errol*, 116 U.S. 517, 525–29 (1886), the court allowed a state tax on goods before their final journey across state lines, reasoning that it would be "untenable to hold that a crop or a herd is exempt from taxation merely because it is, by its owner, intended for exportation."

198 *See* United States v. E.C. Knight Co., 156 U.S. 1 (1895).

199 *See* Phillips Petroleum v. Wisconsin, 347 U.S. 672 (1954). *See generally* Robert R. Nordhaus, *Producer Regulation and the Natural Gas Policy Act of 1978*, 19 NAT. RES. J. 829 (1979) (explaining gap created by the case).

200 *E.C. Knight* aside, the court sanctioned federal regulation when activities

States, therefore, enjoyed a measure of regulatory latitude over instate activities. They could exercise their police power to regulate businesses to protect the public health and welfare.[201] In *Sligh v. Kirkwood*,[202] for instance, the Supreme Court allowed Florida to regulate the sale of citrus fruits destined for interstate commerce. Absent an ability for states, as with Florida in *Sligh*, to regulate the flow of goods into what had fast become a national consumer-oriented market, consumers (at least prior to the FTC

sufficiently influenced interstate commerce. *See, e.g.*, Stafford v. Wallace, 258 U.S. 495 (1922); R.R. Comm'n v. Chi, Burlington & Quincy R.R. Co., 257 U.S. 563, 588 (1922); Ferger v. United States, 250 U.S. 199, 203–04 (1919). The *Shreveport Rate Cases*, for instance, established the Interstate Commerce Commission's authority to affect intrastate rates when a "close and substantial" relationship between the two exists. Hous., E. & W. Tex. R.R. Co. v. United States, 234 U.S. 342, 351 (1914). This same theory justified the court's anti-labor interpretation of the antitrust laws as applying to strikes designed to impede a manufacturer's ability to sell goods into an interstate market. *See, e.g.*, Bedford Cut Stone Co. v. Journeymen Stone Cutters' Ass'n, 274 U.S. 37, 47–49, 54 (1927).

201 *See, e.g.*, Barbier v. Connolly, 113 U.S. 27 (1884) (allowing California to regulate laundries, primarily targeting Chinese immigrants). In the infamous oleomargarine cases, the court in *Plumley v. Massachusetts*, 155 U.S. 461 (1894) allowed the state to prevent the sale of colored margarine, presumably deceiving consumers into believing it was butter. Conversely, in *Schollenberger v. Pennsylvania*, 171 U.S. 1, 14 (1898), the court invalidated as a direct burden on interstate commerce Pennsylvania's complete ban against importing oleomargarine, a legitimate article of interstate commerce according to the court. *See also* Reid v. Colorado, 187 U.S. 137 (1902) (quarantine against infectious cattle within states' power but here preempted by Congress); Patapsco Guano Co. v. Bd. of Agric., 171 U.S. 345, 354 (1898) (North Carolina's fertilizer inspection program, with court commenting "[i]nspection laws are not in themselves regulations of commerce"). In *Hebe Co. v. Shaw*, 248 U.S. 297 (1919), Justice Holmes rejected Fourteenth Amendment and Commerce Clause challenges to Ohio's ability to regulate condensed milk brought in from Wisconsin. Notably, Brandeis joined two conservatives in dissent, reasoning "[w]e are unable to find in these statutes anything which prohibits the sales of condensed, skimmed milk when it is a part of a wholesome compound sold for what it really is, and distinctly labeled as such." *Id*. at 305, 306 (Day, J., dissenting). But Brandeis found nothing arbitrary nor unreasonable about state efforts to regulate the amount of butter fat in ice cream shipped in interstate commerce, to warrant a violation of the Fourteenth Amendment. *See* Hutchinson Ice Cream Co. v. Iowa, 242 U.S. 153 (1916). *See also* Or.-Wash. R.R. & Navigation Co. v. Washington, 270 U.S. 87, 96 (1926) (allowing quarantine against alfalfa hay possibly containing the alfalfa weevil); Amour & Co. v. North Dakota, 240 U.S. 510 (1916) (regulating lard).

202 *See* 237 U.S. 52 (1915). The court in *Sligh* observed how "[t]he right to preserve game flows from the undoubted existence in the state of a police power to that end, which may be none the less efficiently called into play because by doing so interstate commerce may be remotely and indirectly affected." *Id*. at 60.

and passage of robust food and drug laws) could be deceived or worse, defrauded. The court, as a consequence, allowed Indiana to regulate the sale of International Stock Food—an allegedly medicinal drug for domestic animals—into the interstate market.[203] And for natural resources, including potentially wildlife, water, oil, natural gas, coal, and possibly hydroelectric power, as discussed earlier, the court already afforded states greater latitude in their regulation, even allowing in some circumstances favoring instate over out-of-state interests.[204]

But Dormant Commerce Clause principles throughout the pre-New Deal period were fluid, making application to a specific situation—particularly to the new electric utility industry—somewhat problematic. The court had crafted various formulas, which soon thereafter would be abandoned, such as asking whether a particular activity was local or national in character—a concept that surfaced in *Cooley v. Board of Wardens*[205] and received wider endorsement during the end of the nineteenth and early twentieth centuries.[206] The court also had employed other formulaic tests, such as whether an activity directly or substantially burdened interstate commerce, or only indirectly or incidentally burdened interstate commerce.[207] And in many cases, courts were beginning

203 *See* Savage v. Jones, 225 U.S. 501 (1912).

204 *See supra* notes 130–138 and accompanying text. The ability of states to protect against waste and limit production for oil destined for instate markets was upheld (against a Fourteenth Amendment challenge) again in *Champlin Refining Co. v. Corporation Commission*, 286 U.S. 210 (1932). There, the court observed that "[i]t was not shown that the commission intended to limit the amount of oil entering interstate commerce for the purpose of controlling the price of crude oil or its products, or of eliminating plaintiff or any producer or refiner from competition, or that there was in any way combination among plaintiff's competitors for the purpose of restricting interstate commerce . . . ." *Id.* at 232.

205 *See* 53 U.S. (12 How.) 299 (1851).

206 *See* Kalen, *supra* note 104, at 749.

207 *See, e.g.*, Lemke v. Farmers' Grain Co., 258 U.S. 50, 59 (1922) (direct burden). In Shafter v. Farmers' Grain Co., 268 U.S. 189 (1925), Justice Van Devanter noted:

> The decisions of this court respecting the validity of state laws challenged under the commerce clause have established many rules covering various situations. Two of these rules . . . that a state statute enacted for admissible state purposes and which affects interstate commerce only incidentally and remotely is not . . . prohibited . . .and the other that a state statute which by its necessary operation directly interferes with or burdens such commerce is . . . prohibited . . . regardless of the propose . . . These rules, although readily understood and entirely consistent, are occasionally difficult of application . . .

to take a keen interest in whether or not the state or local entity was targeting and, therefore, discriminating against interstate commerce—an inquiry that soon would become the touchstone for most Dormant Commerce Clause analyses.[208]

B. *Whose Case Controls?*

The 1924 *Missouri v. Kansas Natural Gas Co.* opinion, therefore, reflected a narrow band of the Supreme Court's tortured effort to bring some coherence to Commerce Clause jurisprudence, some of which is explored above in Part II. The *Attleboro* litigants argued over the narrow question of *Kansas Natural Gas Co.*'s application, effectively championing the position expressed by the Federal Power Commission. The Federal Power Commission, after all, had somewhat myopically opined in 1925 that the *Kansas Natural Gas Co.* decision naturally extended to electric energy supplied in interstate commerce, leaving the only outstanding question of whether it would apply to all energy sold across state lines or only that sold at wholesale rather than directly to consumers.[209] According to the Commission, most energy sales fell within the first category.[210] Even so, the Commission

> [And] as might be expected, the decisions dealing with such exceptional situations have not been in full accord.

Id. at 199.

208 Elsewhere I suggest how focusing on "discrimination" arose out of a notion that individuals enjoyed a federal right to engage in commerce and from a cross pollination of Fourteenth Amendment jurisprudence. *See* Kalen, *supra* note 104, at 750–63.

209 *See* 5 FED. POWER COMM'N ANN. REP. 8 (1925). While the Commission recognized several instances of interstate transmission, it treated the interstate market as small and not likely to grow too much; nevertheless, it found the issue significant enough to warrant resolving "by whom these interstate energy transfers are to be regulated." *Id.* When, however, the Commission subsequently rejected the notion of interstate compacts to resolve the problem, it raised the specter of too many interstate transactions. *See id.* at 10. Possibly fearful of losing influence, it challenged the idea of a compact for the superpower—commenting how it "would, in effect, have merely created for such purpose another Federal Government to serve in place of the one we now have." *Id.* Oddly, the following year the Commission heralded the success and ability of states and the Commission to coordinate regulating of one of the largest hydroelectric projects of its time, the Conowingo Dam, which would transmit and sell power into various states. *See* 6 FED. POWER COMM'N ANN. REP. 6–9 (1926).

210 Here, the Commission merely quoted from the Supreme Court's natural gas cases to support the claim. *See* 6 FED. POWER COMM'N ANN. REP. at 8–9 (1926).

recommended distinguishing between wholesale sales and sales directly to consumers, believing that this would "simplify the problem of regulation."[211] It explained, in cavalier fashion and with questionable assumptions even at the time:

> Whether or not this separation does in fact take place, the instances in which regulation by the Federal Government will be required will be few in number and simple in character, since they will have to do only with wholesale transactions in interstate commerce. Even in these instances Federal regulation should be limited to those cases in which a formal complaint is filed, and in which the State either alone or in cooperation can not [sic] effectively control the situation. Any attempt to extend Federal regulation to control over rates and services to consumers would be both unnecessary and unwise.[212]

Attleboro's argument, half of which addressed Fourteenth Amendment claims, was quite simple.[213] Because the transaction involved interstate commerce, it was outside state control unless "there is anything to take the case out of the general rule that rates for interstate service rendered by a public utility cannot be fixed by state action."[214] And *Kansas Natural Gas Co*., it argued, was controlling.[215] Attleboro briefly reviewed telegraph, motor carrier, and other cases, but without any appreciation for the nuances of those cases or the court's changing approach toward the Commerce Clause.[216] Overall, the analysis rested upon a simple

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211 The Commission's rationale was that then local distribution companies would be forced to incorporate in their state, eventually splitting the wholesale generation business from retail distribution. *See id*. at 11.

212 *Id*.

213 *See* Brief for the Respondent, Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927) (No. 217).

214 *Id*. at 10.

215 *See id*. Counsel argued that "[t]he service is, moreover, strictly wholesale, the entire product being transmitted to a single recipient, which performs independently [sic] the local service of distribution." *Id*. at 12. Indeed, counsel informed the court "it is unnecessary to consider what the rule would be if the respondent were only one of many customers affected by the order and if the others were all in Rhode Island." *Id*. at 17.

216 For instance, counsel lumped together with little thought and dismissed the natural resource line of cases, *see supra* notes 130–135 and accompanying text, with the statement that "[w]hen the commodity is a natural product and the sale of it may deplete the natural resources of the State, the argument in favor of the right to regulate such sale is exceedingly plausible. This court, however, has refused to recognize any such right even in cases of that kind." Brief for the Respondent, *supra* note 213, at 19.

tautology: If the activity was in interstate commerce, it was an impermissible regulation of interstate commerce, unless it was a valid exercise of a state's police power—which would only occur if it was designed to achieve a traditional police power purpose rather than a regulation of interstate commerce.

Rhode Island countered by describing how Dormant Commerce Clause cases distinguished between direct and indirect interference with commerce, seeking to persuade the court that public utility rate regulation fit within the latter.[217] Its brief accepted a similarity between gas and electric energy,[218] emphasizing how the order did not discriminate against either Attleboro or interstate commerce.[219] According to the Rhode Island, the case involved a classic example of a state regulating a matter of local concern that only indirectly affected commerce because one of Narragansett's customers happened to engage in interstate commerce:[220]

> In the present case it is impossible for the Rhode Island Commission to exercise effectively its power to regulate the rates for electricity furnished to local consumers, without also regulating the rates for other service furnished by the Narragansett Company. On that ground the regulation of such other service should be allowed, even though it incidentally affects interstate commerce.[221]

Rhode Island argued against the application of *Kansas Natural Gas Co*. That case, it asserted, involved an effort by the receiving state (which in this case would be Massachusetts) to keep the price of wholesale gas lower than it had been, which was not the case here. Also, unlike there, the "business of the Company

217 *See* Brief for Petitioners, *Attleboro*, 273 U.S. at 83 (No. 217).

218 "The only difference which might have any bearing on the present case is that with gas (at least natural gas), as with water and oil, the principal element of the cost of furnishing it to a customer is the cost of transportation, while with electricity the principle element is the cost of generating the current." *Id*. at 19. This arguably overlooks the fact that part of the underlying dispute seemingly occurred because of the cost to Narragansett of the transmission line! The state also addressed adverse language in *Galloway v. Bell*, 11 F.2d 558 (D.C. Cir. 1926), *cert. denied*, 271 U.S. 666 (1926), noting simply it was dicta without any additional commentary. *See* Brief for Petitioners, *supra* note 217, at 28–30.

219 *See* Brief for Petitioners, *supra* note 217, at 19.

220 Rhode Island discussed gas and electric cases to illustrate how, when products are sold solely within a state it is a matter of local concern. *See id*. at 19–21.

221 *Id*. at 21 (italics removed).

is chiefly intrastate, not interstate. The paramount interest is local, not national."[222] But when purportedly articulating a line beyond which state jurisdiction could not extend, Rhode Island's brief confusingly stated that the jurisdictional line should be drawn in this case, "even though prohibiting it in cases similar to the *Missouri* [*Kansas Natural Gas Co*.] case."[223] The brief then made two Commerce Clause points: First, Narragansett was a state-franchised company. Second, the rate was for a "commodity produced within the State, as distinguished from a rate for transportation."[224]

C. *The Court Decides*

Responding to these arguments and affirming the Rhode Island Supreme Court, Justice Sanford's majority opinion avoids any serious analytical treatment of the court's evolving struggles with the Commerce Clause. According to Sanford, the court's decision in *Kansas Natural Gas Co*. controlled.[225] With a simple *ipso facto* statement, he announced that the Rhode Island PUC's order establishing a new rate directly burdened interstate commerce and was invalid.[226] With an implicit nod toward the questionable original package doctrine, he added "[t]he forwarding state obviously has no more authority than the receiving state to place a direct burden upon interstate commerce."[227] From there, he proceeded perfunctorily to justify his conclusion.

First, he intimated that if Rhode Island could establish rates

222 *Id*. at 25–26.

223 *Id*. at 27. R.I. admitted its jurisdiction would be doubtful if Narragansett chiefly sold its energy to recipients outside the state, and it further observed that, if Narragansett delivered energy to both local consumers and public utilities in Massachusetts, it likely would be subject to that state's utility commission. *Id*. at 27–28.

224 *Id*. at 30. An amicus brief filed by another company indicated a similar issue was pending elsewhere, and asserted states should be afforded the ability to regulate rates that only indirectly affect interstate commerce. *See* Motion of Southern Sierras Power Co. for Leave to File Brief as Amicus Curiae, *Attleboro*, 273 U.S. 83 (No. 217). *See also* Ariz. Edison Co. v. S. Sierras Power Co., 17 F.2d 739 (9th Cir. 1927) (contract dispute for power being transmitted across state lines), *cert. denied*, 274 U.S. 757 (1927).

225 *See* 273 U.S. at 89. Justice Sanford's opinion poses a binary question: Does the "case come[] with the rule of the Pennsylvania Gas Co. Case [relied on by Rhode Island] or that of the Kansas Gas Co. Case upon which Attleboro Company relies[?]" *Id*. at 87.

226 *See id*. at 89.

227 *Id*. at 90 (citing Pennsylvania v. West Virginia, 262 U.S. 553 (1923)).

for sales in interstate commerce then quite possibly it could discriminate in favor of local residents. The problem with this analysis is that, while the PUC hearing explored Attleboro's claim of discrimination in favor of New England Power, the possibility of discrimination was neither the finding of the PUC nor of the Rhode Island Supreme Court and, as such, Sanford's suggestion could only serve as an abstraction, not a factual assessment.[228] Of course, the PUC-approved "rate" itself was not a rate for interstate sales, it was a rate effectively altering Attleboro's contractual rate—for an interstate sale. It did not, however, on its face target interstate commerce.[229] And while undoubtedly concern about possible discrimination influenced his decision, the posture of the case made it difficult for Sanford to rely on precedent prohibiting states from discriminating against interstate commerce—a holding that might have been less exceptional. How, therefore, the approved rate "directly" "burdened" interstate commerce seems unclear. It is equally hard to assess how much it "burdened" commerce, because Attleboro continued to receive service and had been paying the new rate since the PUC's order. In addition, the new rate cost Attleboro $50,000 annually and there was no analysis of its actual impact on Attleboro or its customers.

Second, Sanford described the "interstate business" of the two companies "as essentially national in character" rather than "local to either state" and as such neither the exporting nor importing state could regulate the rates—instead, it would be a matter "vested in Congress."[230] His attempt to distinguish the two primary cases, *Pennsylvania Gas Co*. and *Kansas Natural Gas Co*., suggests he believed "national character" of the business operated as the critical factor here. Again, though, he offers a simple conclusion. What brings it within the domain of cases employing the local/national (or *Cooley*) rationale is missing. The country already had a national marketplace for most goods and services. Distinguishing between what requires uniformity in treatment and

228 *See id*.

229 Attleboro's counsel argued that the case was "unlike a speed law. . . which applies to all classes of traffic alike," this PUC order "is avowedly aimed solely at the respondent and will not affect any other customer." Brief for the Respondent, *supra* note 213, at 17. Yet, absent a different record or framing the issue differently, the case was presented as an abstract issue of a PUC order that applies to any company purchasing energy under a rate, whether for intra or interstate.

230 *Attleboro*, 273 U.S. at 90.

what does not could not be governed simply by a product's movement in commerce. Surely, rates for the sale of electricity would not need (nor could it be possible) uniform treatment throughout the nation. But that is what Sanford's opinion unfortunately suggests. Perhaps, then, what he meant was that "jurisdiction" over the sale and delivery of electricity in interstate commerce constituted a matter of national not local interest. This would mean it was not the particular order of the Rhode Island PUC changing the contractual rate for the sale, but rather his belief that Attleboro's business of purchasing and transporting electricity in the interstate market through an interconnected system was beyond state interference, warranting national attention.[231] But little about the Supreme Court's precedent suggested that a potentially concurrent exercise of state police power could be prohibited when it would be better if regulated by the national government. Section 20 of the FWPA expressly allowed state regulation of rates for licensees selling energy in interstate commerce, with the FPC given jurisdiction to address complaints in the absence of sufficient state authority.[232] What appears conspicuous, therefore, is that the presumably conservative Sanford—a Chief Justice Taft recruit having joined the court only four years earlier—avoided any factual inquiry or confronting the court's considerable jurisprudence,[233] only a fraction of what this

231 This is how Justice Sutherland framed the question in *Kansas Natural Gas Co*. *See* Missouri *ex rel.* Barrett v. Kan. Nat. Gas Co., 265 U.S. 298, 305 (1924).

232 Federal Water Power Act of 1920, Pub. L. No. 66-280, § 20, 41 Stat. 1063, 1073–74.

233 Little is known about Justice Sanford's judicial philosophy, author of the well-known free speech opinion in *Gitlow v. New York*, 268 U.S. 652 (1925). *See, e.g.*, Lewis L. Laska, *Mr. Justice Sanford and the Fourteenth Amendment*, 33 TENN. HIST. Q. 210 (1974). Alpheus Mason describes "the long-forgotten Edward T. Sanford" as a protégé of—and ideologically aligned with—Chief Justice Taft as a constitutional conservative. MASON, *supra* note 153, at 164, 174 (1964). I suspect that Sanford's background as a conservative yet progressive pushed him toward believing that federal legislation was necessary in the field of energy, a previously neglected area (with the exception of hydroelectric power). In other instances, for example, he appreciated the need for a factual inquiry, such as when he presided over a claim involving Coca-Cola's use of potentially harmful caffeine in its soda. *See* U.S. v. Forty Barrels & Twenty Kegs of Coca-Cola, 191 F. 431, 433 (E.D. Tenn. 1911) (United States alleging the soda was adulterated under the Food & Drug Act of 1906). He purportedly believed strongly that common carriers must furnish unimpaired non-discriminatory service. *See* Postal Cable Tel. Co. v. Cumberland Tel. & Tel. Co., 177 F. 726, 728 (M.D. Tenn. 1910). And in *Bedford Cut Stone Co. v. Journeyman Stone*

Article portrays, and instead rendered a decision seemingly designed to trigger federal legislation.

Finally, Sanford dubiously suggested that the *Kansas Natural Gas Co*. "precedent" was so dispositive to warrant little discussion. Relying almost exclusively on *Kansas Natural Gas Co*., though, had three defects. First, Justice Sutherland's fairly short opinion in *Kansas Natural Gas Co.* treated all too cavalierly state rate regulation for sales of gas into the interstate market as beyond the traditional local police power of states, such as with "inspection laws, quarantine laws, and, generally, laws of internal police . . . ."[234] One scholar argues that Sutherland feared the "whims of turbulent democratic majorities controlled by political factions."[235] While accepting perceived legitimate police power measures, he protected economic freedom when he believed that a state had acted inappropriately.[236] Illegitimate state behavior necessarily surfaced when states sought to discriminate against or impose a particular burden on those engaged in interstate commerce. The style of his opinion mirrored and relied upon on

Cutters' Ass'n, 274 U.S. 37 (1927), decided only a few months after *Attleboro*, Sanford apparently "grudgingly" concurred separately with the anti-labor majority opinion, simply stating in one sentence that *Duplex Co. v. Deering*, 254 U.S. 443 (1920), dictated the outcome. *See* MASON, *supra* 153, at 229.

234 265 U.S. at 307. Although Rhode Island's counsel avoided the issue, sales of gas and electricity differ in key respects: Electricity as opposed to gas cannot be stored, it must be delivered when generated, and with AC current it can flow in different directions toward the path of least resistance if connected to other systems.

235 Samuel R. Olken, *Justice George Sutherland and Economic Liberty: Constitutional Conservatism and the Problem of Factions*, 6 WM. & MARY BILL RTS. J. 1, 6 (1997).

236 Sutherland emulated Justice Field's conservatism and studied law under Thomas Cooley, the conservative scholar and judge who sought to restrain perceived impermissible exercises of state police power. *See id*. at 7. "Thomas Cooley and Stephen Field, both instrumental in the rise of economic substantive due process, emphasized equal operation of the law as the touchstone of economic liberty necessary for individuals to flourish in a thriving democracy." *Id*. Less critically perhaps, Paul Murphy characterized Sutherland as "that prime architect in readapting the law in the twenties to fit the needs of business and in reembodying [sic] the principles of laissez-faire . . . ." PAUL L. MURPHY, THE CONSTITUTION IN CRISIS TIMES 1918–1969, at 112 (1972). The conservative wing of the court seemingly trusted the judiciary more than either federal or state administrative agencies. *See, e.g.*, Fed. Trade Comm'n v. Gratz, 253 U.S. 421 (1920) (limiting the Federal Trade Commission's ability to prosecute unfair methods of competition); Ohio Valley Water Co. v. Borough of Ben Avon, 253 U.S. 287 (1920) (denied water company due process if no opportunity for judicial review of whether rates confiscatory).

nineteenth century opinions that assumed two spheres of jurisdiction, either federal for interstate commerce or state for a police power.[237] Only a few years after *Attleboro*, for instance, Sutherland would ignore *Attleboro* and uphold an Idaho tax on Utah Power & Light (UP&L) even though UP&L's energy was intended for an interstate market.[238] The tax, he reasoned, was imposed on electric generation rather than on transmission.[239] Indeed, in his *Kansas Natural Gas Co.* opinion, Sutherland urged the need for "equality of opportunity and treatment among the various communities and States concerned."[240] That was not, however, the posture of *Attleboro*.

Also, Justice Sutherland's *Kansas Natural Gas Co*. opinion implicitly accepted the moribund "original package doctrine," establishing a jurisdictional divide between state and federal authority once a product ceased its movement in interstate commerce. The original package doctrine, announced by Chief Justice Marshall, insulated foreign imports from state taxation until they were removed from their "original package,"[241] and it had been applied sporadically to interstate rather than foreign

237 He referenced *Robbins v. Shelby County Taxing District*, 120 U.S. 489 (1887), *Welton v. Missouri*, 91 U.S. 275 (1875), and even *Hall v. DeCuir*, 95 U.S. 485 (1877). For how these cases illustrated a paradigm, see Kalen, *Reawakening*, *supra* note 138, at 450–57, 462–83.

238 *See* Utah Power & Light Co. v. Pfost, 286 U.S. 165 (1932). Idaho argued that *Attleboro* was distinguishable because the rate there included a charge for both generation and transmission. Brief of Appellees at 44, *Pfost*, 286 U.S. 165 (No. 722). UP&L argued that, under *Attleboro*, "[i]f the regulation of the rates for which electric energy can be sold to a company distributing such energy in another state burdens interstate commerce, it must follow that the imposition of a tax upon the process which transmits that energy likewise burdens such commerce." Brief for Appellant at 38, *Pfost*, 286 U.S. 165 (No. 722).

239 Utah Power & Light Co., 286 U.S. at 181–82.

240 Missouri *ex rel.* Barrett v. Kan. Nat. Gas Co., 265 U.S. 298, 310 (1924).

241 Brown v. Maryland, 25 U.S. (12 Wheat.) 419 (1827). States presumably regulated foreign products after they were removed from their original packages; courts then examined whether the regulatory regime impermissibly discriminated against interstate commerce. A fascinating example is Washington State's attempt to regulate foreign eggs. A three-member district court canvassed various state inspection and labeling programs and refused to enjoin Washington's undoubtedly discriminatory program designed to alert purchasers of the foreign source of the eggs. *See* Amos Bird Co. v. Thompson, 247 F. 702 (W.D. Wash. 1921). In *New York ex rel. Silz v. Hesterberg*, 211 U.S. 31 (1908), the Supreme Court allowed New York to prohibit the sale of lawfully obtained foreign game because it might be confused with local game during periods when the state prohibited hunting local game.

commerce. Sutherland applied the doctrine when explaining how sales to consumers were local—as if an interstate article had come to rest in the state and could be regulated. Until then, wholesale transactions in interstate commerce were of a national character:

> The transportation, sale and delivery constitute an unbroken chain, fundamentally interstate from beginning to end, and of such continuity as to amount to an established course of business. The paramount interest is not local but national, admitting of and requiring uniformity of regulation. Such uniformity, even though it be the uniformity of governmental nonaction, may be highly necessary to preserve equality of opportunity and treatment among the various communities and States concerned.[242]

Sutherland, therefore, dismissed other natural gas cases, discussed in Part II above, because he viewed them as involving local distribution of gas that had ceased its character of being in interstate commerce. Sanford must have found such reasoning persuasive when, as noted above, he alluded to the problem confronting an importing state.[243]

The original package doctrine nevertheless had lost its appeal by 1927, and only served as at most an illustrative tool. The doctrine as a jurisdictional divide seemed doomed because state or local efforts to regulate traditional activities, now routinely part of interstate commerce and the burgeoning consumer economy, would—if applied—otherwise halt most state police power measures.[244] A good example involved the movie industry. In the 1920s, the movie industry challenged as violating the original package doctrine the ability of states to regulate the showing of

242 *Kan. Nat. Gas Co.*, 265 U.S. at 309–10.

243 *See supra* notes 140-157, 224-226 and accompanying text.

244 When, for example, distributors objected to getting a distributor license for advertising Jell-O Ice Cream Powder, because their product had been shipped from New York to Washington State and still in their original packages, a lower court decided that it was a reasonable regulation to avert a nuisance and rejected the distributor's use of *Brown v. Maryland* and other cases. *See* Jell-O Co. v. Brown, 3 F. Supp. 132 (W.D. Wash. 1926). "It is a matter of hornbook knowledge," wrote another judge, "that the original package statement of Justice Marshall was an illustration, rather than a formula, and that its application is evidentiary, and not substantive." City of Galveston v. Mexican Petroleum Corp., 15 F.2d 208 (S.D. Tex. 1926) (claiming that oil in the case was still in its foreign import state). Congress employed the doctrine, however, in the Harrison Anti-Narcotic Act, distinguishing between wholesalers and retailers. *See* Harrison Anti-Narcotic Act, Pub. L. No. 223, 38 Stat. 785 (1914). *See, e.g.*, Alston v. United States, 274 U.S. 289 (1927).

films. The U.S. District Court for the District of Connecticut issued an impassioned opinion about the authority of states under their police power to oversee the industry. Films at the time, the court opined, were created only in New York and California, and therefore the industry—with the exception possibly those two states—was undoubtedly engaged in interstate commerce. Addressing the application of the original package doctrine, the court explained that the Supreme Court had made it clear that the "analogy between imports and articles in original packages in interstate commerce in respect to immunity from taxation fails."[245]

This description by the district court may have overstated the clarity of the Supreme Court's opinions. Undoubtedly the Supreme Court no longer accepted the original package doctrine as a litmus test. In *Red 'C' Oil Manufacturing Co. v. Board of Agriculture*,[246] it allowed North Carolina to inspect and therefore regulate imported kerosene and other oils for sale in the state. The Supreme Court accepted the lower court's judgment that North Carolina's charge was similar to that of other states, and therefore implicitly not discriminatory.[247] In *Texas v. Brown*,[248] a unanimous court discussed the original package doctrine only when deciding when a state may impose a fee in excess of the cost of inspection and effectively discriminate against interstate commerce.[249] The case involved Georgia's inspection (and tax) program for petroleum and petroleum products brought into the state and then distributed throughout the state to local agencies or distribution stations. The lower court had enjoined the program for products being sold or intending to be sold in their original package. However, it upheld the program for the products being sold after "breaking the original package."[250] Justice Pitney, who would leave the court shortly before *Attleboro*, relied on *American Steel & Wire Co. v. Speed*[251]

245 Fox Film Corp. v. Trumbull, 7 F.2d 715, 722 (D. Conn. 1925), *appeal dismissed*, 269 U.S. 597 (1925).

246 *See* 222 U.S. 380 (1912).

247 *See id*. at 393. *See also e.g.*, Cleveland Ref. Co. v. Phipps, 277 F. 463, 466 (S.D. Ohio 1921) (the state may "collect the necessary expense of its inspection laws, with the result that interstate commerce to that extent would be lawfully burdened").

248 *See* 258 U.S. 466 (1922).

249 *See id*. at 475–76.

250 *Id*. at 472.

251 *See* 192 U.S. 500 (1904).

and *Woodruff v. Parham*[252] to conclude that the doctrine no longer applied—the question instead was whether a state tax discriminates against interstate commerce.[253] This was seemingly settled with *Sonneborn Bros. v. Cureton*.[254] In an account described by Alexander Bickel, a majority of Justices in *Sonneborn Bros.* apparently were inclined to apply the original package doctrine, provoking a drafted dissent by Justice Brandeis rejecting its application and arguing that the determinative factor is whether the measure discriminates against interstate commerce.[255]

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252 *See* 72 U.S. (8 Wall.) 123 (1868).

253 *See Texas*, 258 U.S. at 475–76. Pitney added how his analysis was consistent with *Askren v. Continental Oil Co*., 252 U.S. 444, 449–50 (1920). In *Askren* and the accompanying *Bowman v. Continental Oil Co.*, 256 U.S. 642 (1921), the court confronted a state's ability to tax interstate activity without an effort by the state to separate in-state versus out-of-state activity or receipts. The conservative Justice Day authored *Askren* and with little analysis simply invoked the doctrine. Justice Day similarly authored *Standard Oil v. Graves*, 249 U.S. 389 (1919). *Graves* involved a Washington State oil inspection program for products being shipped into the state from California. The oil "cannot be lawfully sold at all until the importer has paid the inspection fee." *Id.* at 395. Justice Day relied principally upon *Foote v. Maryland*, 232 U.S. 494 (1914), when concluding the fee as applied to the original package was a direct and therefore unconstitutional burden on interstate commerce. This is where conservative justices conflated Commerce Clause and Fourteenth Amendment jurisprudence. The reason programs in *Graves* and *Foote* violated the Constitution, they reasoned, is because the fee was excessive—*i.e*., unreasonable. These justices willingly examined police power measures and, upon finding them unreasonable, concluded they were not a legitimate exercise of the police power and, therefore, must constitute a regulation of commerce. In *Foote*, Justice Lamar concluded that Maryland's oyster inspection fee was disproportionate to the service rendered. *Cf.* Pure Oil Co. v. Minnesota, 248 U.S. 158 (1918) (upholding petroleum inspection fee as reasonable); Gen. Oil Co. v. Crain, 209 U.S. 211 (1908) (holding, in the context of petroleum inspection, that oil is not property in interstate commerce).

254 *See* 262 U.S. 506 (1923).

255 *See* ALEXANDER M. BICKEL, THE UNPUBLISHED OPINIONS OF MR. JUSTICE BRANDEIS 100–18 (1957). Brandeis apparently was skeptical about Justice Pitney. In *Bowman*, 256 U.S. at 642, Pitney had employed the doctrine. Yet, in *Wagner v. City of Covington*, 251 U.S. 95 (1919), Pitney upheld a local license fee imposed on peddlers of goods received from out of the state. Even Justice Holmes, although unnecessary to his opinion, had earlier discussed the doctrine as if it had force. *See* Hebe Co. v. Shaw, 248 U.S. 297, 304 (1919). *See also* Armour & Co. v. North Dakota, 240 U.S. 510, 517 (1916) (rejecting Commerce Clause challenge by noting a retail sale no longer in original package); F. May & Co. v. New Orleans, 178 U.S. 496, 503 (1900) (Justice Harlan questioning concept in case involving cigarette sales). Justice Cardozo would later invoke the doctrine for illustrative purposes in *Baldwin v. G.A.F. Seelig, Inc.*, 294 U.S. 511, 526–27 (1935). *See also* Whitfield v. Ohio, 297 U.S. 431, 439–40 (1936); James Clark Distilling Co. v. W. Md. Ry. Co., 242 U.S. 311, 325, 330 (1917). *See*

His dissent became unnecessary, however, when Chief Justice Taft employed his reasoning and rejected the application of the doctrine to the case. Taft's opinion for the court carefully examined the doctrine, reviewed the court's precedent and concluded that it would not apply; the touchstone would be whether the tax discriminated against interstate commerce.[256]

Sanford's *Attleboro* opinion unfortunately skirted this entire constitutional dialogue animating the Justices before his arrival.

Sanford, moreover, too quickly accepted rhetoric from *Kansas Natural Gas Co.*, reflecting the philosophy of Justices Van Deventer, Day, and his fellow Tennessean James McReynolds, without appreciating the evolution of the constitutional narrative for the Commerce Clause.[257] There, an interstate company threatened to shut off deliveries to local distribution companies (LDCs) if the LDCs refused to pay a higher rate—an additional 5 cents per 1,000 cubic feet of gas. To protect their LDCs, each state sought to enjoin the company from placing its LDC in such a quandary.[258] Justice Sutherland and the other conservatives, such as Van Devanter, failed to appreciate that Commerce Clause jurisprudence had evolved since the nineteenth century. They adhered to rigid jurisdictional categories, asking whether something served a valid police power purpose or constituted a regulation of interstate commerce, the latter being prohibited and the former acceptable if reasonable, not discriminatory, and only indirectly (or incidentally) affecting interstate commerce. The original package doctrine, after all, served as a simplistic formula for distinguishing a regulation of commerce from an exercise of the police power. Illustrative is Justice Van Devanter's opinion in

generally Noel T. Dowling & F. Mores Hubbard, *Divesting an Article of its Interstate Character: An Examination of the Doctrine Underlying the Webb-Kenyon Act*, 5 MINN. L. REV. 100 (1921).

256 *See* 262 U.S. at 508–21. Justice McReynolds concurred, observing that "[a]pparently not great harm, and possibly some good, will follow a flat declaration that irrespective of analogies and for purposes of taxation we will hold interstate commerce ends when an original package reaches the consignee and comes to rest within a state, although intended for sale there in unbroken form." *Id*. at 522 (McReynolds, J., concurring).

257 *See generally* Kalen, *supra* note 104.

258 *See* Missouri *ex rel.* Barrett v. Kan. Nat. Gas Co., 282 F. 341 (W.D. Mo. 1922); Cent. Tr. Co. of N.Y. v. Consumers' Light, Heat & Power, 282 F. 680 (D. Kan. 1922); State *ex rel.* Helm v. Kan. Nat. Gas Co, 208 Pac. 622 (Kan. 1922). The prior rate had been fixed by a federal court and approved by a public utility commission. *See Helm*, 208 Pac. at 622.

Dahnke-Walker Milling Co. v. Bondurant,[259] involving the movement of wheat across state lines by a common carrier: determining whether the transaction was in interstate commerce became dispositive of constitutionality. In another grain case, Justice Day followed *Dahnke* and asked whether North Dakota's grain inspection statute constituted a regulation of interstate commerce, and added that if it regulated interstate commerce, it would fail.[260] Echoing older opinions, Day resurrected the notion of a federal right to engage in interstate commerce only capable of being burdened by Congress.[261] But by 1927 it had become evident, illustrated by the court's decision in *Di Santo v. Pennsylvania*, that such mechanistic formulas no longer captured how to address Dormant Commerce Clause challenges.[262] Dissenting, Justice Stone urged replacing unworkable talismanic tests with searching factual inquiries designed to tease out whether particular matters were of a national or local concern.[263]

Justice Brandeis' dissent in *Attleboro* further illustrates why an appreciation for how Commerce Clause jurisprudence was

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259 *See* 257 U.S. 282, 292–93 (1921).

260 *See* Lemke v. Farmers' Grain Co., 258 U.S. 50, 56 (1922). Day invoked Justice Holmes' stream of commerce concept justifying how regulating goods destined for interstate markets fell inside the federal sphere of interstate commerce. *See id*. at 55 (citing Swift & Co. v. United States, 196 U.S. 375 (1905)). Attleboro expectedly raised *Lemke* in its brief. *See* Brief for the Respondent, *supra* note 213, at 15. Justice Brandeis wrote President Wilson that in *Lemke* "a promising effort of a state to protect itself met its doom." Letter from Louis Brandeis to Woodrow Wilson (March 3, 1922), *in* 5 LETTERS OF LOUIS D. BRANDEIS, *supra* note 153, at 47. Responding to the claim the state validly exercised its police power, Day in *Lemke* dismissed the claim as having "no application where the State passes beyond the exercise of its legitimate authority, and undertakes to regulate interstate commerce by imposing burdens upon it." 258 U.S. at 59. Three months later when the court, per Chief Justice Taft, used the "throat of commerce" concept to uphold the Packers and Stockyards Act, Justice Day did not participate (he left the court six months later). *See* Stafford v. Wallace, 258 U.S. 495, 527 (1922).

261 Justice Day borrowed language about the "privilege of engaging in interstate commerce," a privilege shielded from state or local governments infringement. *Lemke*, 258 U.S. at 59–60. Dissenting, Justices Brandeis, Holmes, and Clarke explained that whether the sale was in interstate commerce or not "does not preclude application of state inspection laws, unless Congress has occupied the field or the state regulation directly burdens interstate commerce." *Id*. at 61, 64 (Brandeis, J., dissenting).

262 *See* Di Santo v. Pennsylvania, 273 U.S. 34 (1927). *See generally* Sam Kalen, *Dormancy Versus Innovation: A Next Generation Dormant Commerce Clause*, 65 OKLA. L. REV. 381, 392 (2013).

263 *See* 273 U.S. at 43–45.

evolving was critical—although lacking in the majority's opinion.[264] Brandeis' background, perhaps more so than any of the other justices, made him acutely aware of the public utility industry.[265] His modern biographer, Melvin Urofsky, observes how "few people of his generation understood so well the inner workings of the economic system."[266] As the people's advocate, Brandeis worked on high profile gas utility matters, as well as on state-granted charters for elevated electric streetcars.[267] Indeed, he may well have come across the utility when examining the associated traction company.[268] Previous opinions by Brandeis,

264 *See* Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83, 91 (1927) (Brandeis, J., dissenting).

265 *See* LEWIS J. PAPER, BRANDEIS 68–79 (1983) (describing his involvement in the "Gas Fight"); *see also supra* note 151 and accompanying text. *E.g.*, Louis D. Brandeis to Daniel Kiefer, July 11, 1913, *in* BRANDEIS LETTERS Vol. III, *supra* note 259, at 132 ("charters should confer upon cities the right of municipal ownership").

266 MELVIN I. UROFSKY, LOUIS D. BRANDEIS AND THE PROGRESSIVE TRADITION 124 (1981). Alpheus Mason, Brandeis' former foremost biographer, explained how the justice was "[k]eenly aware of the new industrial era's complexities." ALPHEUS T. MASON, BRANDEIS AND THE MODERN STATE 55 (1936). "The most influential critic of trusts during his generation, Brandeis served from 1912 until 1916 as Woodrow Wilson's chief economic adviser and was regarded as one of the architects of the FTC [working with George Rublee]. Above all else, Brandeis exemplified the anti-bigness ethic without which there would have been Sherman Act, no antitrust movement, and no Federal Trade Commission." THOMAS K. MCGRAW, PROPHETS OF REGULATION 82, 122 (1984).

267 *See* MASON, *supra* note 266, at 24–37. *See, e.g.*, Louis D. Brandeis, *How Boston Solved the Gas Problem*, AM. REV. REVS. 592 (1907); *see also* Letter from Louis D. Brandeis to Edward Francis McClenen (March 14, 1916), *in* 4 LETTERS OF LOUIS D. BRANDEIS, *supra* note 153, at 120.

268 *See* Letter from Louis D. Brandeis to Charles Sanger Mellen (Nov. 18, 1907), *in* 2 LETTERS OF LOUIS D. BRANDEIS, *supra* note 153, at 48 (searching for financial information of the "United Traction & Electric Co. of Providence"). Brandeis, in fact, fought against the Rhode Island Company's effective parent, the New Haven railroad monopoly. *See* Louis Brandeis, *The New Haven—An Unregulated Monopoly*, BOS. J., Dec. 13, 1912; LOUIS D. BRANDEIS, FINANCIAL CONDITION OF THE NEW YORK, NEW HAVEN & HARTFORD RAILROAD COMPANY AND OF THE BOSTON & MAINE RAILROAD 3, 7, 27 (1907). *See generally* HENRY L. STAPLES & ALPHEUS T. MASON, THE FALL OF A RAILROAD EMPIRE: BRANDEIS AND THE NEW HAVEN MERGER BATTLE (1947); Richard M. Abrams, *Brandeis and the New Haven-Boston & Maine Merger Battle Revisited*, 36 BUS. HIST. REV. 408 (1962). He sufficiently explored the financial situation of the New Haven that he predicted its economic collapse. *See* MASON, *supra* note 266, at 93. And he became familiar with franchises for traction companies. *See* Letter from Louis D. Brandeis to Arthur H. Vandenberg (April 1, 1911), 2 LETTERS OF LOUIS D. BRANDEIS, *supra* note 153, at 419 (talking about his article on the franchise for street railways in Boston).

moreover, had explored aspects of utility regulation.[269] Dissenting in *Pennsylvania v. West Virginia*, he illustrated his predilection toward deferring to expert administrators trained in exploring facts, rather than accepting the majority's willingness to second-guess an administrative judgment.[270] In a letter to Felix Frankfurter, Brandeis posited that the West Virginia case was "decided largely on ground that natural gas had been made an article of interstate com[merce]" and he feared a state would either have to prevent its "power" from entering the interstate market and risk "robbery" or secure federal legislation that delegated authority to the states to regulate the market.[271] This seemed all the more justified because Justice Holmes had, in 1905, observed how "commerce among the States is not a technical legal conception but a practical one drawn from the course of business."[272]

In his *Attleboro* dissent, Brandeis began by observing that the Rhode Island PUC had exercised a valid police power over a matter of local concern involving one of its own utilities to ensure against discrimination of rates for customers within Rhode Island.[273] He then illustrated why resolving whether it offended the

269 *See* Galveston Elec. Co. v. City of Galveston, 258 U.S. 388 (1922); Missouri *ex rel.* Sw. Bell v. Pub. Serv. Comm'n, 262 U.S. 276 (1923) (Brandeis, J., concurring).

270 This case, Urofsky posits, exemplifies the fight over emerging principles of administrative law and deference to expert agencies. *See* UROFSKY, *supra* note 88, at 614–15. In *Jay Burns Baking Co. v. Bryan*, 264 U.S. 504, 517–34 (1924) (Brandeis, J., dissenting), Brandeis presented a flurry of facts to undermine the ill-conceived assumptions of the majority opinion striking down Nebraska's standard weight bread law. Several years later, Brandeis would explain how "[t]he certificate of public convenience and necessity is a device—a recent social economic invention—through which the monopoly is kept under effective control by vesting in a commission the power to terminate it whenever that course is required in the public interest." New State Ice Co. v. Liebmann, 285 U.S. 262, 280, 304 (1932) (Brandeis, J., dissenting). Brandeis, after all, introduced the notion of a "Brandeis" brief where the court would be presented with actual economic and social facts surrounding legislative activity. *See* MASON, *supra* note 266, at 136–46; *see also* NANCY WOLOCH, MULLER V. OREGON (1996).

271 Letter from Louis D. Brandeis to Felix Frankfurter (June 17, 1923), *in* 5 LETTERS OF LOUIS D. BRANDEIS, *supra*, note 153, at 98. Brandeis recognized the uncertainty surrounding Congress' ability to sanction state activity if the matter was considered exclusively national by "applying the Webb-Kenyon doctrine." *Id*. *See also supra* note 153 (noting case poorly argued).

272 Swift & Co. v. United States, 196 U.S. 375, 398 (1905).

273 *See* Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83, 91, 92 (1927) (Brandeis, J., dissenting).

Commerce Clause required a more thorough analysis than the majority opinion suggested.[274] Simply because the matter involved a transaction in interstate commerce and could be regulated by Congress did not, he believe, answer the question.[275] Until Congress acted, or unless congressional silence suggested that the matter should be free from regulation until Congress acts, the state's exercise of its police power was not restrained.[276] The principal issue, instead, was whether the order of the Rhode Island PUC somehow obstructed or directly burdened interstate commerce.[277] Here, he opined that preventing discrimination against its own citizens was "not obstruct[ing] or plac[ing] [such] a direct burden on interstate commerce."[278] It would be no different, he reasoned, than if the state had simply placed an added tax on the cost of a product that would then be sold into the interstate market. Nor was it, according to Brandeis, any different than the *Pennsylvania Gas Co*. case.[279] He ended his dissent with two principles generally permeating Dormant Commerce Clause jurisprudence: the state had neither discriminated against interstate commerce nor sought to regulate a business engaged solely in interstate commerce.[280]

Justice Sanford ignored altogether Brandeis' dissent, however. Federal legislation was now necessary to regulate *any* electricity that would be transmitted in interstate commerce. A utility commission rate that applied to both intrastate and interstate sales could not be enforced against the latter.[281] There was no distinction between retail or wholesale sales, although Sanford's indirect reliance on the questionable original package doctrine may have suggested such a distinction. It may be that Sanford was aware of the FPC's assessment and implicitly sought to trigger a federal response and issued an opinion with such a sweeping

274 *See id*.
275 *See id*.
276 *See id*.
277 *See id*.
278 *Id*.
279 *See id.* (citing Penn. Gas Co. v. Pub. Serv. Comm'n, 252 U.S. 23 (1920)).
280 *See id*.
281 Parties could still contract for such sales, but the obligation would become fortified against changes by one party or that party's utility commission. In 1928, the FTC reported that, while interstate sales might not be supervising by state commissions, the rates were still low. *See* 1928 FED. TRADE COMM'N ANN. REP. 28.

suggestion. Or, it may well be that Sanford was influenced by the well-recognized need for federal involvement in protecting against abuses within the corporate structures of the electric utility industry.[282] And perhaps he intended the opinion would signal that not only was the FWPA constitutional,[283] but also that a uniform federal approach would make more sense. He had, after all, ended his opinion with precisely that call.

D. *The Desired Result?*

The opinion ignited a desire for a congressional response, particularly as the industry already had become interconnected across state lines. Only the year before, the *Washington Post* reported that Secretary of Commerce Herbert Hoover projected that "there will develop a series of superpower stations, located at strategic points, and serving vast territories over a network of transmission lines" that could be addressed by regional

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282 That issues of corporate structure were intertwined with utility regulation is captured by a *New York Times* report on *Attleboro*:

> The efforts of some large holding companies to evade State regulation by various devices, utility men fear, may result in all being placed more speedily under Federal regulation. Charges of excessive capitalization, inflated organization expenses and exaggerated valuations made in interstate consolidations of electrical companies, it is argued, may then come under the scrutiny of Federal officials, while the task of analyzing the various complex factors entering into the production and interchange of electricity would be enormous and expensive.

Federal Control of Power Forecast, N.Y. TIMES, Jan. 16, 1927, at E13. A few years earlier the Federal Power Commission observed how state commissions could not effectively establish rates because of their inability to examine "the accounts of public utilities." 5 FED. POWER COMM'N ANN. REP. 5 (1925). The FTC investigations begun amid widespread reports about the industry—infusing even dialogues about educators' independence. *See generally* KING, *supra* note 68, at 169–72, 198–206.

283 *See* New Jersey v. Sargent, 259 U.S. 328 (1926) (dismissing for lack of jurisdiction on what today would be standing, although recognizing Congress' authority to regulate navigable waters). *Cf.* Econ. Light & Power Co. v. United States, 256 U.S. 113 (1921) (upholding Congress' authority under Rivers & Harbors Act of 1899 to regulate activities on waters previously navigable and potentially navigable in the future). The authority to pass the Act would be questioned a few years later, as well. *See* KING, *supra* note 68, at 220–25. The Attorney General, for instance, opined how the Commission could exercise authority over projects on non-navigable water only if the Commission found the project would affect commerce. *See Issuance of License for Water Power Development on New River, VA.*, 36 U.S. Op. Att'y Gen. 355 (1930), 1930 WL 1800 (issuing minor part licenses); *see also* United States v. Appalachian Elec. Power Co., 311 U.S. 377 (1940) (affirming jurisdiction over New River project).

cooperation among states through compacts, and if monopolies spanned too many states then those monopolies could be federally regulated.[284] That notion became moot once the Supreme Court decided *Attleboro*. Indeed, the press reported how the opinion effectively stymied efforts at regional coordination and establishing a superpower system.[285] The *New York Times* reported that *Attleboro* established a "New Principle" that "transmission of electric power across State borders is 'interstate commerce' . . . not subject to regulation by State Commissions."[286] The decision was "particularly interesting, lawyers hold, because Congress has not attempted to vest in any Federal agency the regulation of electric power sales from one State to another."[287]

For the FPC, *Attleboro* was a clear victory. The next year the Commission parroted its observations from a few years earlier—undoubtedly anxiously awaiting some new authority.[288] This time it added, presumably as a consequence of the apparent importance of *Kansas Natural Gas Co.*, that its analysis of drawing a line between wholesale sales and sales to a local distribution company was the appropriate jurisdictional line. The Commission's report suggested that such a division would make sense, because only in the latter circumstance could a state arguably (the receiving or importing state) exercise jurisdiction under the—albeit moribund—original package doctrine.[289] The Commission ended

284 *Interstate Power Systems*, WASH. POST, Dec. 20, 1926, at 6.

285 *See Federal Control of Power Forecast*, N.Y. TIMES, Jan. 16, 1927, at E13.

286 *Bars State Control of Exported Power: Supreme Court Decides Rhode Island Cannot Tax for Electricity Sent to Bay State*, N.Y. TIMES, Jan. 4, 1927, at 40.

287 *Id*.

288 *See* 8 FED. POWER COMM'N ANN. REP. 8 (1928). When the Commission again suggested instances of interstate transactions would be low, it nevertheless referenced Conowingo Dam as an example of an interstate sale to a local distribution company, *see supra* note 209, and then cited the Attleboro example. *See* 8 FED. POWER COMM'N ANN. REP. at 8–9. Later, however, the Commission observed how such interstate transactions, at the time constituting roughly "9 percent of the total of power generated," were likely to "becom[e] increasingly more numerous." *Id*. at 12–13.

289 "When the interstate commerce consists of the importation from without a State by a corporation or other agency, which itself sells and delivers the imported energy to its customers, the State may regulate the rates of charges made to such customers until the subject matter is regulated by Congress." 8 FED. POWER COMM'N ANN. REP. at 10. The Commission further indicated it lacked jurisdiction over wholly intrastate transactions (unless under Section 19 of

its review of *Attleboro* with a few conclusions and recommendations. It proclaimed the federal government enjoyed "ultimate authority to regulate interstate commerce in electric energy electric energy," that such authority was "exclusive" when transfers involved wholesale sales (again presumably as a consequence of the original package doctrine), that federal regulation of all transactions would be too cumbersome, and that too much authority in the states might prompt "interstate conflicts or deadlocks or inaction."[290] Eschewing any formal recommendation, it then posited how states might be given exclusive authority over intrastate transactions, and original jurisdiction over interstate transactions subject to the power of "some Federal agency" to supervise and act as an appellate body if necessary.[291]

E. *Congressional Response*

Congress resolved the regulatory "gap" in 1935, eight years after *Attleboro*, passing what is now Part II of the Federal Power Act, and also passing the Public Utility Holding Company Act that same year. "The primary purpose of Title II, Part II of the 1935 amendments to the Federal Act," the Supreme Court wrote in 1943, "was to give a federal agency power to regulate the sale of electricity across states lines" that *Attleboro* "denied to the States."[292] It gave the FPC (which would later become the Federal Energy Regulatory Commission, or FERC) jurisdiction over "the transmission of electric energy in interstate commerce and . . . the sale of electric energy at wholesale in interstate."[293] And it

the Act the state lacked a utility commission); but it enjoyed exclusive authority over interstate wholesale sales by its licensees; and it could exercise jurisdiction over local sales of interstate electricity wherever a state lacked a commission or the commission lacked authority. *See id*. at 11–12.

290 *Id*. at 13.

291 *Id*. Shortly after Congress passed the FPA, the Commission's counsel explained to the trade association that the goal of the FPA was to "strengthen and supplement" rather than "supplant" the "regulatory power of the states." Harry M. Miller, *State and Federal Regulation—Their Proper Spheres*, PUB. UTIL. FORT. 30, 33 (1950). Miller lamented that this understanding became shattered when the court issued *Jersey Central Power & Light Co. v. Federal Power Commission*, 319 U.S. 61 (1943).

292 *Jersey Cent.*, 319 U.S. at 67–68.

293 16 U.S.C. § 824(b)(1) (2012). It defined such interstate transactions as energy "transmitted from a State and consumed at any point outside thereof." § 824(c). It further defined "sale of electricity at wholesale" as "a sale of electric

disclaimed, except as otherwise specifically allowed, any federal authority "over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[294]

CONCLUSION

It is too simplistic to suggest that the language of the FPA mirrored any line identified by Sanford in *Attleboro* or that it addressed a particular jurisdictional "gap." Sanford's perfunctory analysis effectively ignored the context of the case and, as such, produced a categorical holding: it required federal regulation of the industry because (1) the rate applied to a product, electricity, that was being delivered across state lines and warranted national rather than local attention, and (2) because of an unstated risk that in-state residents might be favored. *Attleboro*, though, did not itself establish a line between wholesale and retail sales to customers in another state. That was a line the Commission had drawn, and it would be a line fabricated by commentators, justified merely because of Sanford's citation to the *Pennsylvania Gas Co*. case.[295] "Thus there is a gap,"[296] now the *Attleboro* gap, which prompted the congressional response and presumably filling the gap for wholesale sales.

When, therefore, the Supreme Court later held that *Attleboro* "reiterated and accepted the holding of *Pennsylvania Gas Co*. . . . that sales across the state line direct to consumers is a local matter within the authority of the agency of the importing state,"[297] it perpetuated a particular understanding of *Attleboro*, not necessarily an accurate one—the case presumably appeared too dubious to

energy to any person for resale." § 824(d).

294 16 U.S.C. § 824(b)(1).

295 *See*, *e.g*., Scott, *supra* note 99, at 138–39 (noting that *Attleboro* applied to wholesale sales and that, while not expressly decided, likely did not apply to retail sales because the court "evidently deems analogous to power" what it had held in *Pennsylvania Gas Co.* for natural gas).

296 *Id*. at 139. Professor Noel T. Dowling accepted this reading of *Attleboro* as well. *See* Noel T. Dowling, *State Control of Interstate Power Transmission—The Doctrine of Congressional Permission*, 14 PROC. ACAD. POL. SCI. 132 (1930).

297 United States v. Pub. Utils. Comm'n, 345 U.S. 295, 711 (1953).

accept at face value absent the line and subsequent gap. The parties had litigated whether *Kansas Natural Gas Co*. or *Pennsylvania Gas Co*. governed, and Sanford simply accepted the former. His analysis may have intimated an acceptance of the rejected original package doctrine embedded in *Pennsylvania Gas Co*., but that is about it. His reasoning, though, rested on the asserted national character of the business and a perceived need to avoid discrimination—neither of which necessarily justifies a retail/wholesale divide. And while *Attleboro* was neither analytically sound when issued, nor consistent with how Dormant Commerce Clause analysis would unfold shortly thereafter,[298] its ghost remains with us today.

Some observers adhere to *Attleboro* and argue that states can regulate wholesale transactions when the sales and consumers are located within the same state.[299] But most academic conversations about today's electric grid accept *Attleboro* and focus instead on exploring new governance structures that blur the line between state and federal authority, by encouraging regional governance and cooperation rather than any increased state authority.[300] These dialogues collectively reflect the urgency of incorporating renewable energy into the grid and displacing fossil fuel generation.[301] Ashira Ostrow, for instance, posits that states and

298 *See* Kalen, *supra* note 104.

299 *See generally* Frank R. Lindh & Thomas W. Bone, Jr., *State Jurisdiction Over Distributed Generators*, 34 ENERGY L.J. 499 (2013). The authors argue states may establish feed-in-tariffs, or the wholesale purchase price for renewable energy resources a utility will pay the generator.

300 Alexandra Klass and Elizabeth Wilson, for instance, encourage developing regional compacts to address transmission constraints. *See* Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 VAND. L. REV. 1801, 1804 (2012).

301 *See, e.g.*, *Symposium*, *Greening the Grid: Building a Legal Framework for Carbon Neutrality*, 39 ENVT. L. 929 (2009); Christopher J. Bateman & James T.B. Trip, *Toward Greener FERC Regulation of the Power Industry*, 38 HARV. ENVTL. L. REV. 275 (2014); Alfred C. Lin, *Lessons from the Past for Assessing Energy Technologies for the Future*, 61 U.C.L.A. L. REV. 1814 (2014). One noted constraint is the ability to construct interstate electric transmission lines: transmission facilities capable of carrying renewable resources far from their source must overcome the hurdles of state siting, cost allocation, integration with the grid and reliability issues for the balancing authority, and in organized markets the appropriate financial incentives and approvals. *See generally* Ashley C. Brown, Jim Rossi, *Siting Transmission Lines in a Changed Milieu: Evolving Notions of the "Public Interest" in Balancing State and Regional Considerations*, 81 U. COLO. L. REV. 705 (2010); Klass & Wilson, *supra* note

the federal government could work more effectively together when encouraging or discouraging infrastructure development, and that one solution could be to establish a "National Network Coordinator" that could "coordinate—rather than replace—state regulation . . . ."[302] Hari Osofsky and Hannah Wiseman propose instead that we develop a hybrid structure that merges the governmental pyramid with other stakeholders to create a regional institution.[303] These suggestions by Ostrow, Osofsky, and Wiseman were, in some form or another, also discussed around the time of *Attleboro* but shelved once *Attleboro* forced Congress' hand.[304]

In practice, however, an effective transition to a different energy grid may necessitate re-examining or abandoning *Attleboro*'s purportedly simplistic "bright line." An advisor to a FERC commissioner wrote in 1986 that

> much of the debate . . . centers on which side of the "bright line" one thinks the regulatory function in question should reside. That thinking, of course, underlies most of the strong positions take on the Narragansett doctrine, which really

300; Jim Rossi, *The Trojan Horse of Electric Power Transmission Line Siting Authority*, 39 ENVTL. L. 1015 (2009). Projects also must overcome occasionally fierce opposition from affected property owners. The $2 billion, over-700-mile high-voltage direct-current merchant transmission line proposed by Clean Line would deliver wind energy to distant markets, and yet it has encountered several hurdles at the state level. *See generally* Leslie Newell Peacock, *The Messy Clean Line Issue*, ARK. TIMES, June 18, 2015; Jeffery Tomich, *Clean Line Transmission Project in Limbo After Mo. Rejection*, E&E NEWS, July 2, 2015. Arkansas' Senator Lamar even weighed in against the project, believing it would not benefit Arkansas. *See* Dave Flessner, *Sen. Larmar Alexander Questions Need for Wind Energy Transmission Line to TVA*, TIMES FREE PRESS, May 14, 2014.

302 Ashira P. Ostrow, *Grid Governance: The Role of a National Network Coordinator*, 35 CARDOZO L. REV. 1993, 1996 (2014).

303 *See* Hari M. Osofsky & Hannah J. Wiseman, *Hybrid Energy Governance*, 2014 ILL. L. REV. 1, 12 (2014). *See also* Hari M. Osofsky & Hannah J. Wiseman, *Dynamic Energy Federalism*, 72 MD. L. REV. 772 (2013). Daniel Lyons similarly encourages a regional structure embodying cooperative federalism, rather than what he sees as the "dual federalism approach embodied by the Federal Power Act [that] offers a false dichotomy between state and federal regulation." Daniel A. Lyons, *Federalism and the Rise of Renewable Energy: Preserving State and Local Voices in the Green Energy Revolution*, 64 CASE WESTERN RES. L. REV. 1619, 1624 (2014). Robin Craig accepts the trend toward regional governance and explores the constitutional issues confronting state and local governments when they do so. *See generally* Robin K. Craig, *Constitutional Contours for the Design and Implementation of Multistate Renewable Energy Programs and Projects*, 81 U. COLO. L. REV. 771 (2010).

304 *See* Frankfurter & Landis, *supra* note 164, at 709.

> comprises the effort to legally police the *Attleboro* "bright line."[305]

The first chairman of FERC (when the agency changed from the FPC to FERC in the 1970s), along with other prominent energy experts, expressed the view that "federal and state regulators will 'muddle through'" the jurisdictional divide.[306] That muddling includes—so far unsuccessful—efforts by states to wrest from FERC's jurisdiction the ability to control aspects of local or regional electric generation capacity markets. The Fourth Circuit invalidated Maryland's program for encouraging new capacity in the wholesale market, reasoning that the *Attleboro* line and resulting FPA placed that authority exclusively within FERC's domain,[307] with the Supreme Court concluding that the FPA preempted Maryland's program.[308] The Third Circuit held that the FPA similarly preempted New Jersey's program for incentivizing the construction of new electric generation facilities.[309] And the Second Circuit rejected New York's challenge to FERC's presumption for the dividing line between the bulk power system under its domain and local distribution under state jurisdiction.[310] State efforts to entice renewable generation beyond the bounds of the Public Utility Regulatory Policies Act are similarly being challenged as transgressing an *Attleboro* line.[311] And along with

305 Reinier H.J.H. Lock, *Models for Bulk Power Deregulation: What Promise for the Future?*, 38 ADMIN. L. REV. 349, 358 (1986).

306 Rod Kuckro, *Without Congress Acting, Electric Markets Will 'Muddle Through'—Panel*, E&E NEWS, Sept. 8, 2014. Robert Nordhaus explains how the court in *Federal Power Commission v. Southern California Edison Co.* (*Colton*), 376 U.S. 205, 206–07 (1964), effectively solidified the *Attleboro* "bright line" and how in recent years "a host of new jurisdictional issues have challenged the states, the FERC, and the courts in applying the 1964 Bright Line." Robert R. Nordhaus, *The Hazy "Bright Line": Defining Federal and State Regulation of Today's Electric Grid*, 36 ENERGY L.J. 203, 207 (2015).

307 *See generally* PPL Energyplus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014).

308 *See* Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288 (2016).

309 *See generally* PPL Energyplus, LLC v. Solomon, 766 F.3d 241 (3d Cir. 2014). *See also* N.J. Bd. of Pub. Utils. v. FERC, 744 F.3d 74, 80 (3d Cir. 2014) (discussing *Attleboro*, Congress' response, and the modern jurisdictional divide, when deciding challenge to tariff for PJM).

310 *See generally* New York v. FERC, 783 F.3d 946 (2d Cir. 2015) (New York questioned the presumptive threshold for local distribution lines at 100 kV, adopted for implementing reliability standards under the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594).

311 *See, e.g.*, Allco Fin., Ltd. v. Klee, 805 F.3d 89 (2d Cir. 2015) (rejecting jurisdiction to challenge against Connecticut program, where lower court

these challenges there is the escalating chorus of scholarship fearful that the Dormant Commerce Clause is chilling state and local efforts to reduce greenhouse gas emissions.[312] The Dormant Commerce Clause even surfaced as an issue in the initial stages of the highly publicized Cape Wind offshore wind project, when Massachusetts originally required utilities within the state to acquire renewable generation located "within the jurisdictional boundaries of the commonwealth."[313]

The continued resonance of the *Attleboro* jurisdictional line surfaced in FERC's defense of its regulations of demand response to reduce greenhouse gas emissions. In Order No. 745, FERC required that certain large customers, including factories and commercial facilities, receive full market prices when they reduce their consumption.[314] The concept is simple. Instead of increasing generation of electricity to meet consumer demand, possibly from fossil fuel fired plants, the grid operator can request that certain consumers reduce their demand and thus avoid the need for additional energy generation. Demand response, therefore, provides an attractive option for greening the grid.[315] One of the

concluded that *Attleboro* line not violated).

312 *See generally* Jeffery S. Dennis, *Federalism, Electric Industry Restructuring, and the Dormant Commerce Clause:* Tampa Electric Co. v. Garcia *and State Restrictions on the Development of Merchant Power Plants*, 43 NAT. RES. J. 615 (2003); Steven Ferrey, Chad Laurent & Cameron Ferrey, *Fire and Ice: World Renewable Energy and Carbon Control Mechanisms Confront Constitutional Barriers*, 20 DUKE ENVTL. L. POL'Y F. (2010); Kalen, *supra* note 262; Lindh & Bone, *supra* note 299; Ari Peskoe, *A Challenge for Federalism: Achieving National Goals in Electricity Industry*, 18 MO. ENVTL. L. & POL'Y REV. 209 (2011); *see also* KATE KONSCHNIK & ARI PESKOE, MINIMIZING CONSTITUTIONAL RISK: CRAFTING STATE ENERGY POLICIES THAT CAN WITHSTAND CONSTITUTIONAL SCRUTINY (2014), https://statepowerproject.files.wordpress.com/2014/11/minimizing-constitutional-risk2.pdf. *See, e.g.*, Rocky Mountain Farmers Union v. Corey, 730 F.3d 1070 (9th Cir. 2013) (rejecting challenge to state low carbon fuel standard).

313 *See generally* Town of Barnstable v. O'Connor, 786 F.3d 130 (1st Cir. 2015) (describing program and noting geographical limitation subsequently removed). *See also* Energy & Envtl. Legal Inst. v. Epel, No. 14-1216, 2015 WL 4174876 (10th Cir. July 13, 2015) (rejecting challenge to Colorado renewable standard).

314 *See* Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187, 2011 WL 890975 (2011) (to be codified at 18 C.F.R. pt. 35). The order applies to both real time and day ahead markets and requires compensation for the full market price for the energy based on the locational marginal price.

315 FERC defines "demand response" as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an

leading scholars on demand response, Joel Eisen, writes that it is important for FERC to possess the authority to require demand response.[316] The grid is becoming "smarter," allowing enhanced and two-way communication between consumers and energy suppliers, and accompanying this evolution of the electric grid is the ability to manage our electric needs with more precision and deliberation than we have in the past.[317] FERC has promoted this in the wholesale market. Put simply, FERC provided a compensation mechanism for enticing entities that regulate the grid and operate wholesale markets (Independent System Operators and Regional Transmission Organizations) "to use demand-side resources to meet their systems' needs for wholesale energy, capacity, and ancillary services."[318] The D.C. Circuit Court of Appeals, however, held that FERC intruded into states' authority to regulate retail sales—embodied in the FPA.[319] After the Supreme Court accepted certiorari, the solicitor general argued that *Attleboro* established "that the Commerce Clause bars States from regulating *certain* interstate electricity transactions, such as wholesale power (*i.e.*, a sale for resale)" by a utility "across state

increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy." 18 C.F.R. § 35.28(b)(4) (2012). In the 2005 Energy Policy Act, Congress encouraged demand response. Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 966 (2005). For discussions about reducing demand and demand response, see Michael P. Vandenbergh & Jim Rossi, *Good for You, Bad for Us: The Financial Disincentive for Net Demand Reduction*, 65 VAND. L. REV. 1527 (2012).

316 *See generally* Joel B. Eisen, *Who Regulated the Smart Grid?: FERC's Authority Over Demand Response Compensation in Wholesale Electricity Markets*, 4 SAN DIEGO J. CLIMATE & ENERGY L. 69 (2012–2103).

317 *See generally* Joel B. Eisen, *An Open Access Distribution Tariff: Removing Barriers to Innovation on the Smart Grid*, 61 U.C.L.A. L. REV. 1712 (2014); Joel B. Eisen, *Smart Regulation and Federalism for the Smart Grid*, 37 HARV. ENVTL. L. REV. 101 (2013).

318 *See* Elec. Power Supply Ass'n v. FERC, 763 F.3d 216, 219 (D.C. Cir. 2014), *rev'd*, 136 S.Ct. 760 (2016). *See generally* Sharon B. Jacobs, *Bypassing Federalism and the Administrative Law of Negawatts*, 100 IOWA L. REV. 885 (2015).

319 *See generally Elec. Power Supply Ass'n.*, 763 F.3d 216. FERC subsequently rejected PJM's (a regional transmission organization) effort to change its tariff to allow wholesale entities to bid load reductions into three year out capacity markets. PJM Interconnection, LLC, 150 FERC ¶ 61,251 (March 31, 2015). Former FERC Commissioner Wellinghoff reflects how, when the Commission issued Order No. 745, "no one seriously challenged" whether it had jurisdiction to address demand response. *Former FERC Chairman Defends Demand-Response Program as it Heads to Supreme Court*, BNA DAILY ENVT. (June 8, 2015).

lines."[320] In upholding FERC's program, the court agreed how it had previously prohibited states from regulating wholesale interstate sales when it "created what became known as the '*Attleboro* gap.'"[321] However, that is an illusion, and it was not accurate then and it is not accurate now.

320 Brief for Petitioner at 3, FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760 (2016) (No. 14-840) (emphasis added), 2015 WL 4237680, at *3.

321 FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760, 767 (2016). While endorsing the divide between retail and interstate wholesale rates, the court nonetheless, according to Jim Rossi and former commissioner Wellinghoff, "approached FERC's jurisdiction in a functional manner, endorsing pragmatism over formalism in the regulation of energy markets." Jim Rossi & Jon Wellinghoff, FERC v. EPSA *and Adjacent State Regulation of Customer Energy Resources*, 40 HARV. ENVTL. L. REV. F. 23, 24 (2016).

CLE READING MATERIALS

The Future of Distributed Generation: Moving Past Net Metering

FOR

10:15 a.m. – 11:35 a.m. **ADVANCING ENERGY POLICY**

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- **Cheryl LaFleur**, Commissioner, Federal Energy Regulatory Commission
- **Andrew G. Place**, Vice Chairman, Pennsylvania Public Utility Commission

Moderator: **Burcin Unel**, Energy Policy Director, Institute for Policy Integrity

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ARTICLE

The Future of Distributed Generation: Moving Past Net Metering

Richard L. Revesz and Burcin Unel, Ph.D.

Richard L. Revesz is the Lawrence King Professor of Law and Dean Emeritus, New York University School of Law.
Burcin Unel is the Energy Policy Director, Institute for Policy Integrity at the New York University School of Law.

I. Introduction

"Distributed generation" is a term used to describe electricity that is produced at or near the location where it is used.[1] Distributed generation systems, also known as distributed energy resources, can rely on a variety of energy sources, such as solar, wind, fuel cells, and combined heat and power.[2] Over 90% of the current distributed generation capacity in the United States is solar,[3] and the number of installations is increasing rapidly.[4] As a result, many states are in the process of changing their utility structures and regulatory policies to accommodate more distributed energy resources.[5]

Most distributed generation systems are grid-tied, which means that they are connected to a utility's power grid.[6] Customers with connected distributed generation systems can buy power from their electric utility when they are not producing enough electricity to meet their needs, and sell power back to the utility company when their systems are producing more electricity than they are using.[7]

The question of how these customers should be compensated for that electricity they send to the grid has three significant policy implications. First, it plays a key role in determining the economic feasibility of clean electricity relative to electricity produced by fossil fuels. Second, distributed generation has benefits for the electric grid's resilience, as it provides a more diversified portfolio of energy sources than schemes that rely exclusively on centralized power plants.[8] Finally, the details of how distributed generation is compensated for various benefits will affect the composition of future clean energy projects.

Net metering is the most commonly used approach for setting distributed energy compensation.[9] The traditional net metering approach is functionally equivalent to having a single meter that runs forward when the customer needs more power than she produces, and backward when she sends excess power to the grid.[10] At the end of the billing period, the customer is billed at the retail electricity rate

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1. *Distributed Solar*, Solar Energy Indus. Ass'n (2015), https://perma.cc/MA74-45JJ.
2. American Public Power Ass'n, Distributed Generation: An Overview of Recent Policy and Market Developments A 3 (2013), https://perma.cc/62YC-P85G.
3. *See id.* at 2–3.
4. Interstate Renewable Energy Council, Trends Shaping Our Clean Energy Future: The 2014 IREC Perspective 25 (2014), https://perma.cc/359X-ZMTW [hereinafter IREC, Trends Shaping Our Clean Energy Future].
5. *DPS—Reforming the Energy Vision,* N.Y. Dep't Pub. Serv., https://perma.cc/BB5Y-VFPA (announcing broad regulatory changes that promote "wider deployment of 'distributed' energy resources"); D.C. Pub. Serv. Comm'n, Formal Case 1130, Comment on the Scope of the Proceeding (Aug. 31, 2015), https://perma.cc/EG5M-PK68 (calling for grid modernization with a "focus on deployment of distributed energy resources"); Mass. Dep't of Pub. Utils., Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, D.P.U. Order 12-76-B, 2 (June 12, 2014), https://perma.cc/6FZR-8J5Q (requiring every Massachusetts electric provider to submit a 10-year plan outlining how the utility will "integrate distributed resources."
6. Andrew Mills et al., *Net Metering*, Sunlight Elec (July 2015), https://perma.cc/6S48-YKKQ.
7. Edison Electric Inst., Straight Talk About Net Metering 1–2 (Jan. 2016), https://perma.cc/E5FF-C54F.
8. Devi Glick et al., Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future 16 (Rocky Mountain Inst. Aug. 2014), https://perma.cc/JNK4-52T7.
9. Straight Talk, *supra* note 7 (laying out electric industry arguments against net metering).
10. *Id.* at 2.

for the net power used.[11] In effect, suppliers are paid at the retail rate for their excess generation.[12]

As of October 2016, 45 states and the District of Columbia compensated utility customers with distributed generation for the power they generated.[13] Even though details of individual state approaches vary, in this Article, we use the term "net metering" to refer to the practice of compensating distributed generation customers at the retail price, which remains the most common practice.[14]

Utilities concerned about lost revenues have begun urging state legislatures and public service commissions to impose fixed charges for net metering customers and to decrease the rate of compensation those customers receive for the energy they generate.[15] Environmentalists and individuals seeking to generate their own electricity for financial or libertarian reasons have argued opposite positions.

One goal of this Article is to evaluate the respective arguments. An ideal pricing mechanism would take into account the potential environmental and health benefits of cleaner energy and the grid-related costs resulting from distributed generation. Our second goal is to provide an alternative compensation structure for distributed solar generation that can also be used consistently and fairly for all types of energy sources. Our final goal is to highlight the need to analyze net metering in the context of more comprehensive energy policies, such as much-needed reform in electricity pricing policy.

II. Net Metering Policies

The most common tool to track electrical output and compensate distributed generation owners is a billing arrangement known as net metering.[16] The 2005 Energy Policy Act catalyzed distributed generation by offering favorable tax treatment to individuals installing solar generators and by encouraging state adoption of net metering policies[17] that allow individual utility customers to produce and sell energy in state-regulated retail markets.[18] However, despite the near-ubiquitous adoption of net metering by states, the policies differ among jurisdictions.[19]

First, state net metering programs differ in how they compensate customer-sited generation. Currently, 34 net metering jurisdictions credit customers for generation at the retail rate,[20] which exactly mirrors the price charged by utilities to end-use consumers for electricity.[21] Only seven jurisdictions exclusively credit net excess generation at the avoided cost rates,[22] which reflect the cost to a utility of generating equivalent power or purchasing it from a non-qualifying facility third-party.[23] Many states offer a combination of rates.[24] A second variation is how long a customer's monthly excess generation may be "carried over" to future billing cycles. As of October 2016, net generation may be carried over month-to-month and applied in subsequent billing periods to offset later usage in all but two jurisdictions.[25] Third, nearly all jurisdictions place a cap on the maximum permissible size of any individual net-metered generator.[26] Fourth, 24 jurisdictions set aggregate capacity limits that constrain the total amount of net-metered generation permissibly installed within a state or utility service area.[27]

The differences among net metering policies can significantly affect the attractiveness of distributed generation to utility customers. Over 76% of net-metered distributed generation systems are located in states with favorable net metering policies.[28]

III. Evaluating Current Pricing Approaches

A. *Net Metering*

The argument that a kilowatt hour (kWh) of electricity produced and sent to the grid by a distributed generator should be compensated at the retail rate is grounded in the basic principles of perfectly competitive markets, in which buyers and sellers buy or sell the product at the same market-clearing price determined by the marginal cost of

11. *Id.*
12. Naïm R. Darghouth et al., Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment 1 (Lawrence Berkeley Nat'l Lab. July 2015), https://perma.cc/Y7GK-69WW.
13. The only states that do not offer a statewide net metering policy are Alabama, Idaho, South Dakota, Tennessee, and Texas. Best Practices in State Net Metering Policies and Interconnection Procedures, Freeing the Grid (2015), https://perma.cc/USG7-HR3U [hereinafter Best Practices].
14. *See* Steven Ferrey, *Virtual "Nets" and Law: Power Navigates the Supremacy Clause*, 24 Geo. Int'l Envtl. L. Rev. 267, 267 (2012); Benjamin Hanna, *FERC Net Metering Decisions Keep States in the Dark*, 42 B.C. Envtl. Aff. L. Rev. 133, 133–34 (2015).
15. Peter Kind, Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business 18 (Edison Elec. Inst. 2013); *see also* Solar Energy Indus. Ass'n, Solar Market Insight Report: 2014 Year in Review (2015).
16. U.S. Energy Info. Admin., State Energy Data System, Net Metering Customers and Capacity by Technology Type, by End Use Sector, 2004 Through 2014, tbl. 4.10 (2013), https://perma.cc/4C44-9JDK (noting a 53% annual growth rate in NEM customers); *see also* J. Heeter et al., Status of Net Metering: Assessing the Potential to Reach Program Caps 12 (Nat'l Renewable Energy Lab. 2014), https://perma.cc/2KPV-KC2M (noting net metering is a statistically significant driver of solar growth).
17. Energy Policy Act of 2005 § 1251, 16 U.S.C. § 2621(d) (2012).
18. According to the "net sales" test, retail market transactions include transactions between a utility customer and the utility as long as the customer does *not* consistently produce sufficient excess energy (beyond their own energy consumption) during a given time period to be considered a "net seller" of electricity. *See* 16 U.S.C. § 824(a).
19. *See* Best Practices, *supra* note 13.
20. *Id.*
21. Yih-huei Wan & H. James Green, Current Experience With Net Metering Programs 1-2 (Nat'l Renewable Energy Lab., 1998), https://perma.cc/5CRH-D5AL.
22. Best Practices, *supra* note 13.
23. Wan & Green, *supra* note 21, at 1-2.
24. Laurence D. Kirsch & Mathew J. Morey, Pricing Retail Electricity in a Distributed Energy Resources World (Christensen Ass'n Energy Consulting 2015), https://perma.cc/U5CN-R9SJ.
25. Best Practices, *supra* note 13.
26. *Id.*
27. *See Net Metering State Database*, Database of State Incentives for Renewables & Efficiency, https://perma.cc/NA52-4BMV.
28. *See* Best Practices, *supra* note 13 (noting states with favorable net metering policies).

production. However, many retail electricity tariffs use inefficiently designed, flat volumetric per-kWh rates. These rates are intended to cover not only the variable costs of the generation of electricity itself, but also fixed costs and a reasonable rate of return for the utilities.[29]

1. Shortcomings of a Bundled, Flat Volumetric Rate

A typical tariff for residential customers has two parts, a fixed monthly service charge and a flat, volumetric energy-consumption charge. Consequently, utilities' ability to recover their costs depends on the volume of electricity sold. The retail electricity price is essentially the bundled average cost of providing retail electricity to a customer, which includes electricity generation and additional services, as well as transmission, balancing, and local distribution. Hence the electricity sent to the grid by a distributed generator, which lacks those additional services, is not a perfect substitute for the retail electricity consumed by the end-user. When net-metered customers are compensated using retail rates, they avoid paying for the costs already incurred for their reliance on grid-delivered electricity and for the demand they place on the grid.[30]

2. Temporal and Locational Variations, and Production and Transmission Constraints

Another source of inefficiency in electricity pricing stems from the way in which energy charges are calculated for retail customers. Demand for electricity is higher at certain "peak" demand times during the day, and utilities use more expensive generators during these periods to meet demand. When variation in costs is not reflected in retail rates, net metering compensates distributed generation using the same flat volumetric rate at all times and locations. As a consequence, net metering policies lead to overcompensating distributed generation exports during off-peak times and undercompensating them during peak times, effectively exchanging a high-value product for a low-value one.

3. Demand Variations and Distribution Constraints

A consumer's contribution to the fixed costs of local distribution networks is also dependent on the time and location of consumption. The maximum demand during peak periods is the main driver of any new distribution system capacity investment.[31] A customer's maximum demand at the moment of highest usage among all customers in a particular location—"coincident peak demand"—is more important as a driver of infrastructure investments than the customer's individual peak demand—"non-coincident peak demand."[32] When distributed generation lowers the coincident peak demand at a location that is close to the peak network capacity, it lowers the need for future distributed capacity investment. As this variation is not reflected in the flat volumetric retail rates, common net metering policies cannot sufficiently capture the full value of distributed generation.

4. Equity Considerations

The mismatch between the way in which costs are incurred and how they are recovered due to flat, volumetric rates gives rise to the possibility of cost shifting among different customer groups when one group lowers its consumption for any reason, whether it is a result of distributed generation, energy efficiency, or personal preference. With net metering, while customers who own solar panels essentially get credited for the output they produce at the retail rate by being billed for a lower net volume of electricity, customers without distributed generation systems end up having to make up the lost revenue with higher rates.[33] Net metering is often disproportionately concentrated among wealthier customers. Thus, many fear that net metering acts as a socially regressive subsidy for utility customers with distributed generation by placing additional costs on moderate- and low-income customers.[34]

B. Fixed Charges and Net Metering Caps

An increase in fixed charges that applies only to distributed generators, as suggested in some states, would hurt efficiency if it does not reflect the costs that they actually impose on the grid.[35] Converting distribution expenses into flat service fees also ignores actual variation in delivery costs and undervalues the savings achieved by the *distributed* nature of distributed generation. Simply increasing fixed service charges can therefore transfer cost burdens from rural, higher-use ratepayers, who require greater delivery costs, to urban and low-use ratepayers, for whom these costs are lower.[36]

To the extent that a utility cannot recover its costs with the prevailing retail rates, a net metering cap could alleviate the cost recovery concerns of utilities. However, given that a proper tariff design would alleviate any cost recovery concerns, an arbitrary net metering cap would only lead to further inefficiency and under-deployment of distributed generation.

29. *See* Tom Tanton, Reforming Net Metering: Providing a Bright and Equitable Future 1-5 (Am. Legis. Exch. Council 2014, https://perma.cc/K4XF-6BRD.
30. *Id.* at 1.
31. Paul Simshauser, *Distribution Network Prices and Solar PV: Resolving Rate Instability and Wealth Transfers Through Demand Tariffs*, 54 Energy Econ. 108, 108-09 (2016).
32. *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Staff White Paper on Ratemaking and Utility Business Models*, Case No. 14-M-0101, N.Y. PSC, Filing No. 416 at 80 n.81 (July 28, 2015).
33. *See* Tanton, *supra* note 29, at 9-11.
34. Ashley Brown, *Valuation of Distributed Solar*, 27 Elec. J. 27, 27 (2014), https://perma.cc/C35M-G2QV.
35. Darghouth et al., *supra* note 12, at 6–8.
36. Jim Lazar, Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed 59 (Reg. Assistance Project 2013).

IV. Evaluating the Contributions of Distributed Generation to the Electric Grid

A. *Benefits of Distributed Generation to the Electric Grid*

The clearest benefit of distributed generation to the overall electrical system is that it avoids the cost of operating a bulk system generator to meet customer demand. Avoided energy benefits can be especially significant if distributed energy resources help avoid generation from costlier "peaker" plants. Distributed energy resources also provide value to the transmission and distribution system; electricity travels shorter distances to the end user, directly curtailing energy losses that may occur because of inefficient power lines. Distributed renewables offer long-term cost savings by enabling utility and state entities to defer or avoid large capital investments in new fossil fuel generators, transmission, and distribution infrastructure.[37] Finally, distributed generation can be invaluable to providing power supply during extreme weather events such as storms or other emergency situations.

B. *Costs of Distributed Generation to the Grid*

The costs of distributed generation go beyond the costs of installing new meters. As electricity cannot be stored on a large scale, customer usage must be met in real time by utility generation.[38] Significant mismatches between consumer demand and available power supply can cause grid frequency levels to drop,[39] which may damage generator turbines or lead to blackouts.[40] The dependence of most distributed generation on weather conditions inescapably means that its output is variable and patterned, which can hamper the grid's reliability and interfere with its efficient operation.[41]

Unregulated, bi-directional energy flow introduced by net-metered customers also imposes additional strains on the physical electric grid,[42] leading to increased flow management and voltage regulation costs,[43] and may overload the circuits close to the distributed generator.[44] Another related challenge is that distributed solar units cannot be intentionally fueled or dispatched with certainty to meet consumer demand at a particular time.[45] As a result, utilities must provide adequate backup power. Erratic changes in output make matching electric generation and customer usage difficult,[46] and can require other power plants to remain online simply to ensure that adequate power is available to meet demand,[47] thereby forgoing environmental benefits of distributed generation and doing little to reduce the operational costs of utilities.[48] However, these costs can be lowered or eliminated as technology and forecasting methods become more advanced.

V. Considering the Social Benefits of Distributed Generation

The primary external benefit of distributed generation is arguably the reduced carbon dioxide emissions from fossil fuel sources displaced by distributed generators. Other benefits include public health and welfare improvements, water conservation, land preservation, and reductions in physical infrastructure necessary to support fossil fuel electricity generation.[49] As these benefits are not fully reflected in current retail tariffs, the existing net metering policies do not capture the true value of distributed generation to society, and will thus lead to less distributed generation than is socially optimal.

A. *Incorporating Climate Change Benefits*

1. Quantifying Net Avoided Emissions and Valuing Avoided Carbon Dioxide Emissions

The first step in valuing the climate change benefits of distributed generation is to calculate the amount of net avoided emissions. Avoided emissions depend on the type of generator that the distributed generation is displacing and thus the time and location of the energy generated.[50] The quantity of greenhouse gas emissions avoided by distributed generation should be calculated by looking at the quantity of emissions that the marginal generator at that location would have emitted at the time of the distributed generation production. This feature is a missing quality in

37. Anderson Hoke & Paul Komor, *Maximizing the Benefits of Distributed Photovoltaics*, 35 Elec. J. 55, 55–61 (2012).
38. *See* Timothy P. Duane, *Legal, Technical, and Economic Challenges in Integrating Renewable Power Generation Into the Electricity Grid*, 4 San Diego J. Climate & Energy L. 1, 7-9 (2013).
39. Erik Ela et al., Active Power Controls From Wind Power: Bridging the Gaps 40 (Nat'l Renewable Energy Lab. 2014), https://perma.cc/XA7K-GRDP.
40. *Id.* at 1.
41. Tanton, *supra* note 29, at 4.
42. *See* Am. Pub. Power Ass'n, *supra* note 2, at 11 (potential safety issues involving distributed generation include "islanding," high-voltage spikes, out-of-phase reclosing, and system-wide blackouts).
43. *See* Mass. Inst. of Tech., The Future of the Electric Grid 17, 64 (2011), https://perma.cc/UKE4-SM36; *see also* Elec. Power Research Inst., The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources 14 (2014), https://perma.cc/U77P-W893.
44. *See* Am. Pub. Power Ass'n, *supra* note 2, at 11.
45. Severin Borenstein & James Bushnell, *The U.S. Electricity Industry After 20 Years of Restructuring*, 7 Ann. Rev. Econ. 437, 455 (2015).
46. N. Am. Elec. Reliability Corp., Accommodating High Levels of Variable Generation ii (2009), https://perma.cc/NL4X-XNU4 [hereinafter NERC Report].
47. *See* Borenstein & Bushnell, *supra* note 45, at 455.
48. Lori Bird et al., Integrating Variable Renewable Energy: Challenges and Solutions 3-4 (Nat'l Renewable Energy Lab. 2013), https://perma.cc/28B5-XK8Y.
49. Lazar, *supra* note 36, at 50.
50. *See* Kyle Siler-Evans et al., *Regional Variations in the Health, Environmental, and Climate Benefits of Wind and Solar Generation*, 110 PNAS 11768, 11770 (2013).

current net metering or "value of solar" policies. The second step is to monetize the quantity of avoided emissions based on estimates of the monetary value of the damage they impose on society. Currently, the best estimate of the marginal damage caused by carbon emissions is the social cost of carbon (SCC).

2. Interaction With Other Regulatory Approaches

The variation in state policies regarding distributed generation is not limited to the specifics of net metering policies. States provide a variety of different incentives for renewable energy resources, and specifically for solar panels, including tax credits, for example.

The existence of other policies aimed at reducing emissions does not change the marginal external cost of carbon emissions, which is the monetary value of all the damages caused by one additional unit of emission. Thus, the marginal external damage associated with each additional unit of emissions is exogenously determined, and is independent of any other environmental policies that are in effect. If, however, there are other policies in effect that cause fossil fuel generators to internalize some of the external damage they are causing, then the environmental benefit adjustment in remuneration of distributed generation should only include the "uninternalized" damages.

The existence of a cap-and-trade program complicates the calculation of the quantity of net avoided emissions. A precise calculation of the quantity of net avoided emissions in the presence of a cap-and-trade program requires an in-depth study of how distributed generation affects the number of unused allowances and how fast those unused allowances in turn affect the long-term level of the cap. An alternative approach would be to use the quantity of emissions displaced by the distributed generator as an approximation. Once the quantity of avoided emissions is calculated, it can be then multiplied by the SCC to monetize the environmental benefits of distributed generation.

VI. Toward an "Avoided Cost Plus Social Benefit" Approach

The efficient price for distributed generation should reflect all of its costs and benefits, both private and external. Net metering falls short of accomplishing this goal because the current retail electricity rates do not fully reflect either the true marginal cost of electricity generation or the associated externalities. A new approach is needed until comprehensive retail rate reform corrects such inefficiencies. As state efforts to evaluate and reform net metering become increasingly common, it is important to establish a socially desirable framework that can be used consistently in different states and for different types of distributed energy resources.

An "Avoided Cost Plus Social Benefit" approach that compensates distributed generation for the net avoided cost and net social benefits is preferable to net metering. Distributed generation should be compensated for social benefits such as environmental and health benefits while taking into account the additional costs imposed by distributed generation and rewarding distributed generation only for costs it avoids, thus eliminating utilities' concerns about recovering costs of existing infrastructure. Until recently, the Federal Energy Regulatory Commission (FERC) explicitly prohibited the inclusion of externality adders in avoided-cost rates in the wholesale markets.[51] However, in 2010, FERC changed course, and ruled that avoided cost rates could permissibly differentiate between "various [qualifying facility] technologies on the basis of the supply characteristics of the different technologies" opening the way to incorporating environmental benefits that are monetized through compliance with state policies such as renewable portfolio standards.[52] Thus, state utility commissions now have discretion to tailor avoided cost rates for certain policies,[53] and "the authority to dictate the generation resources from which utilities may procure electric energy,"[54] opening the door to avoided-cost rates that reflect the characteristics of a qualifying facility.

VII. The Promise of Time-, Location-, and Demand-Variant Pricing

The "Avoided Cost Plus Social Benefit" approach to compensating distributed generation advocated in this Article is only a stopgap measure until comprehensive retail electricity reform can take place. The first-best solution to the problems caused by net metering is simply to correct the inefficiencies of the retail rates.

Current tariff designs almost universally use one flat volumetric price per kWh to recover costs incurred in non-volumetric ways. Using a cost-reflective tariff that is properly unbundled and granular would improve overall system efficiency and the value of distributed generation. First, a bundled, flat volumetric rate insulates consumers and producers from receiving the correct price signals about the true social cost of generating energy. As a result, consumers have no incentive to adjust their usage based on the actual cost of electricity. More importantly, a flat rate prevents prices from being interpreted as efficient investment signals.

Second, using a flat volumetric rate that is uniform across the service territory of a utility undercompensates distributed generation for other benefits it provides, such as reducing grid congestion when the system is close to capacity during peak hours. Third, a flat volumetric rate creates perverse incentives for customers during the installation phase. As net-metered customers are compensated using the same flat rate regardless of what time they send

51. S. Cal. Edison Co., 70 FERC ¶ 61,215 (1995), 71 FERC ¶ 61,269 (1995).
52. *See* Cal. Pub. Utils. Comm'n, 133 FERC ¶ 61,059, 61,628 (2010).
53. Kaylie E. Klein, *Bypassing Roadblocks to Renewable Energy: Understanding Electricity Law and the Legal Tools Available to Advance Clean Energy*, 92 Or. L. Rev. 235, 258 (2013).
54. Cal. Pub. Utils. Comm'n, 134 FERC ¶ 61,044, 61,160 (2011).

energy to the grid, their inherent incentive is to install solar panels with the goal of maximizing their total production, and hence compensation, rather than overall power system benefits. Finally, the amount of greenhouse gas emissions displaced by distributed generation also depends on time and location. Once again, the use of a flat volumetric rate that does not granularly reflect changes in the external costs of electricity generation prevents the realization of the full value of distributed generation.

A. *Valuing Distributed Generation With Time-, Location-, and Demand-Variant Pricing*

The efficiency problems created by the interaction of net metering policies and inadequate retail rate designs are preventable. Regulators need only move toward more sophisticated rate designs that are unbundled—with generation, distribution, and transmission valued and priced separately—and more cost-reflective.[55] Thus, costs are recovered similarly to the way they are incurred, based on the unit of their drivers. For example, energy generation costs that are based on the volume of energy sold should be recovered using volumetric charges. To avoid any cross-subsidization, volumetric energy charges should be designed to reflect the variation in locational and temporal changes in the cost of providing electricity.

Similarly, distribution network charges should be carefully designed.[56] If the highest electricity capacity a customer needs at a particular time period is driving the need for further infrastructure investment, charges based on this coincident peak demand could be imposed. To ensure that existing network costs are recovered fairly, a charge based on connected load, similar to a network subscription charge, could be imposed.[57] Cost-reflective retail tariff rate structures that provide customers proper price signals that reflect the actual costs underlying the provision of electricity, including the associated externalities, will improve economic efficiency.

B. *Equity Issues*

Any significant tariff change should be implemented with regard for the stakeholders who stand to lose in the short term. The possibility of such transitional equity problems should be recognized, and policy solutions aimed at these problems should be discussed as part of any reform. However, keeping volumetric rates artificially low is not the solution to equity concerns regarding vulnerable low-income energy customers. Social welfare is maximized when the market price reflects both private and external marginal costs.[58] Once such a price is established so that the maximum possible net benefits can be realized, distributing this net value among different groups of stakeholders is best done through direct transfer programs that have specific policy goals, such as crediting low-income customers with fixed amounts on their energy bills, or subsidizing programs that would allow low-income customers easier access to distributed energy resources.

C. *Incorporating Externalities Into Dynamic Pricing*

Internalizing externalities like environmental and health benefits in retail rates and tariff design aimed at maximizing net social benefits is crucial to the success of clean energy policies, especially when dynamic tariffs are used. While dynamic tariffs using time-, location-, and demand-variant pricing provide more incentives for distributed generation deployment and result in a decreased energy demand from the bulk system, they may also cause consumers without distributed generation systems to shift their loads to periods where dirtier plants are on the margin, unless the externalities are fully internalized in retail rates.

As peaker plants are often less efficient and dirtier,[59] overall emissions decrease when distributed generation reduces the need for the electricity generated from such plants. However, if time-varying rates shift consumption to other periods, calculating the net effects requires a more careful analysis. If the temporal dimensions are not taken into account while calculating environmental and health benefits, and all distributed energy resources are rewarded based on the same average quantity of avoided emissions, market incentives will lead to more investment in cheaper distributed energy resources, regardless of whether they are the most beneficial for society when taking externalities into account.

Overall, having the right price signals would ensure an efficient allocation of resources by directing the right type of distributed energy resource investments to where they are needed most. While solar panels may be more valuable when installed near areas where demand peaks during the day, investing in wind turbines may be more valuable in areas where demand peaks later in the day, as that is when wind production also peaks.[60] Only by using a comprehensive framework that can recognize granular variations in valuation can we move beyond narrow, short-sighted debates that may inefficiently favor one low-carbon resource over another.

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55. Ahmad Faruqui, The Global Movement Towards Cost-Reflective Tariffs 30–31 (Brattle Group 2015), https://perma.cc/6QH4-GAB3.
56. *See generally,* Toby Brown et al., *Efficient Tariff Structures for Distribution Network Services*, 48 Econ. Analysis & Pol'y 139 (2015).
57. Ahmad Faruqui, The Case for Introducing Demand Charges in Residential Tariffs (Brattle Group 2015), https://perma.cc/8HQY-4Q5G.
58. *See* Jonathan Gruber, Public Finance and Public Policy 127, 138–42 (MacMillan Higher Education, 4th ed. 2012).
59. Robin Bravender & Collin Sullivan, *Utility to Build First Power Plant With Greenhouse Gas Emissions Limits in California,* Sci. Am. (Feb. 5, 2010), https://perma.cc/Q4GW-TGWU; *see also Flexible Peaking Resource*, Energy Storage Ass'n, https://perma.cc/9YUH-5AXV; Janice Lin, *The Value of Energy Storage*, Cal. Energy Storage All. (Mar. 25, 2014), https://perma.cc/R2MM-M23G.
60. *See generally* Joseph Cullen, *Measuring the Environmental Benefits of Wind-Generated Electricity*, 5 Am. Econ. J.: Econ. Pol'y 107,107-133 (2013).

VIII. Conclusion

As many states are looking to integrate more distributed energy resources into the grid, current net metering policies are proving to be inadequate to properly value the clean energy produced by distributed generation, or the services provided by the electric grid and the utilities.

Our analysis identifies the sources of the inefficiencies of current policies and we propose a preferable protocol, which we refer to as the "Avoided Cost Plus Social Benefit" approach. This approach both rewards clean distributed energy for the environmental and health benefits it provides and ensures that utilities are compensated for the services they provide. This approach is the best that can be accomplished given the limitations of the current energy policy framework, which relies too heavily on fixed volumetric rates. Finally, this Article provides a roadmap for more comprehensive energy policy reform, which is necessary in order to properly value all energy resources, including distributed generation, and thereby ensure that states' clean energy and resilience goals can be achieved as efficiently as possible.

CLE READING MATERIALS

Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System

FOR

10:15 a.m. – 11:35 a.m. **ADVANCING ENERGY POLICY**

- **Kathleen Frangione**, Chief Policy Advisor, Office of the Governor for the State of New Jersey
- **Cheryl LaFleur**, Commissioner, Federal Energy Regulatory Commission
- **Andrew G. Place**, Vice Chairman, Pennsylvania Public Utility Commission

Moderator: **Burcin Unel**, Energy Policy Director, Institute for Policy Integrity

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ELECTRICITY POLICY INSIGHTS

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Toward Resilience

Defining, Measuring, and Monetizing Resilience in the Electricity System

August 2018
Burcin Unel, Ph.D.
Avi Zevin

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street
New York, New York 10012

Burcin Unel is the Energy Policy Director at the Institute for Policy Integrity. Avi Zevin is an Attorney at the Institute for Policy Integrity.

Executive Summary

Resilience—the electric grid's ability to resist, absorb, and recover from high-impact, low-probability external shocks—is an important, yet wide-ranging and potentially amorphous concept. Many different actions can help the grid defend against, absorb, or recover from high-impact, low-probability shocks. However, some potential actions will do little to address specific threats and have been suggested for what appears to be political reasons. Moreover, many actions that can significantly enhance electric system resilience come at substantial cost. Systematically and transparently evaluating the cost of a potential resilience-enhancing action and its expected impact on the probabilities and consequences of grid outages is critical to evaluating whether that action is worthwhile from an economic efficiency perspective or whether it is misguided. To ensure that we make only efficient and cost-beneficial investments, decisionmakers must adopt a clear and useable definition of resilience, identify potential actions that improve resilience, and conduct an economic analysis of the social value of those actions. Only by engaging in this type of analysis can policymakers ensure that they do more than simply pick winners based on political preferences.

This report aims to assist policymakers in understanding grid resilience and evaluating potential interventions aimed at improving it. The following key insights can help policymakers improve the resilience of the electric system by acknowledging and responding to real threats in a systematic, transparent, and accountable way.

Defining and measuring resilience are necessary first steps.

- Grid resilience is a broad concept that can be simplified into a four-part framework. A resilient electric system is one that has the ability to (1) avoid or resist shocks, (2) manage disruption, (3) quickly respond to a shock that occurs, and (4) fully recover and adapt to mitigate the effects of future shocks.

- Resilience can be measured based on the performance of the system or its components (e.g., number of customer outage hours, monetized value of lost economic productivity). It can also be based on the attributes of the system or its components (e.g., how hardened the distribution system is to high winds, the extent to which replacement transmission components are readily available, the extent to which a generator is vulnerable to fuel-supply disruption). Attribute-based measures are easier to develop but also are potentially more misleading. Because of interactions among different threats and components of the electric system, improving one attribute may or may not improve resilience as a whole. Moreover, many of the attributes that have been suggested in recent federal policy discussions—such as whether a plant has historically operated to serve baseload demand or whether a plant was utilized during an extreme weather event—do not have a demonstrated connection to resilience. Performance-based metrics more directly measure resilience, are more reflective of the multi-faceted nature of resilience, and are more useful than system or resource attributes in quantitative analysis (such as cost-benefit analyses of potential resilience interventions).

- Investments to improve the resilience of individual components of the electric system—generation resilience, transmission resilience, distribution resilience—should all be considered, but must be measured with respect to how they improve overall *electric system resilience*.

Resilience policies and investments should be evaluated using a cost-benefit analysis framework.

- Policymakers should use a systematic, transparent framework for evaluating potential interventions, to ensure that the benefits of resilience-enhancing investments and policies justify the costs.
- A framework developed by Sandia National Labs is analytically intensive but can provide critical insight when comparing potential resilience interventions. This framework involves specifying threats, defining performance-based resilience metrics, using computer-modeling simulations to understand and monetize probabilistic baseline levels of resilience, and comparing those levels with monetized probabilistic estimates of resilience after potential interventions.
- The benefits identified using this framework can be compared to the costs of the policy or investment, including the costs to the utility of making investments, costs to customers that result from market rules that change energy prices, costs associated with any countervailing resilience risks, and environmental costs that result from changes to the grid mix.

In general, sufficient legal authorities exist at the state and federal levels to implement cost-beneficial resilience improvements.

- Because most customer outages are the result of disruptions to the distribution system, substantial focus on resilience should be on states, who have the authority to regulate distribution system investments and policies. States have numerous authorities to require resilience improvements.
- The federal role in enhancing resilience is restricted but important. The Federal Energy Regulatory Commission can use its authority over transmission investments, reliability standards, planning and coordination, and electric market rules to implement any identified cost-beneficial improvements to the bulk power system.
- The Department of Energy is vested with authority to respond to grid emergencies in the unlikely circumstance that existing market rules and reliability standards prove insufficient to respond to a high-impact, low-probability event. That authority must be exercised within the confines provided by Congress and subject to judicial review.

The Trump Administration's proposals to provide cost-based financial support to coal and nuclear plants do not reflect the best-practices for policy intended to support electric system resilience outlined in this report.

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Introduction

Grid resilience—the electric grid's ability to resist, absorb, and recover from high-impact, low-probability external shocks—has concerned electric utilities and grid planners for decades. However, a recent series of extreme weather events and cybersecurity incidents, and political efforts by the Trump Administration to prop up certain favored generation sources, have brought a renewed focus to this critical electric sector issue.

In the United States, Superstorm Sandy in 2012 and the Polar Vortex in 2014 kicked off the recent focus on grid resilience as a critical infrastructure priority, resulting in congressionally mandated studies,[1] federally directed policy changes,[2] new state energy policies,[3] and private-sector investment and innovation.[4] A series of high-impact, low-probability events during the summer and fall of 2017 brought grid resilience back into the news, prompting discussion of policy changes to prepare for events such as hurricanes,[5] wildfires,[6] cybersecurity incidents,[7] and high-profile power failures.[8]

The Trump administration's attempts to promulgate policies that support coal and nuclear power plants under the pretense of enhancing resilience have also drawn attention to the issue. In September 2017, the United States Department of Energy (DOE) issued a controversial and high-profile directive to the Federal Energy Regulatory Commission (FERC) to consider and act on a proposal to provide economic support to power plants that maintain 90-days' worth of on-site fuel (primarily coal and nuclear plants).[9] DOE justified the need for this support by claiming these plants provide essential grid resilience benefits that wholesale electric markets fail to sufficiently value. FERC ultimately rejected DOE's proposal but initiated a proceeding to request additional information from grid operators on how to think about and enhance resilience.[10] More recently, President Trump ordered DOE to develop policies to forestall retirement of coal and

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1 Nat'l Acad. of Sci., Eng'g & Med., Enhancing the Resilience of the Nation's Electricity System vii (2017), https://www.nap.edu/catalog/24836 [hereinafter NAS] (describing the report's origin in a 2014 Congressional mandate that the Department of Energy conduct a "national-level comprehensive study on the future resilience and reliability of the nation's electric power transmission and distribution system").

2 *Order on Technical Conferences*, 149 FERC ¶ 61,145 (Nov. 20, 2014).

3 2015 New York State Energy Plan at 34-35, https://energyplan.ny.gov/-/media/nysenergyplan/2015-overview.pdf (discussing extreme weather events that contributed to the development of New York's "Reforming Energy Vision" energy policy).

4 Magdalena Klemun, *5 Market Trends That Will Drive Microgrids Into the Mainstream*, Green Tech Media (Apr. 9, 2014), https://www.greentechmedia.com/articles/read/5-market-trends-that-will-drive-microgrids-into-the-mainstream (showing microgrid investment was driven by recent extreme weather events).

5 This includes a series of hurricanes in the Gulf of Mexico that caused significant power outages, resulting in damage and lost economic opportunity in Texas and Florida. *See* Karma Allen & Maia Davis, *Hurricanes Harvey and Irma May Have Caused Up to $200 Billion in Damage, Comparable to Katrina*, ABC News (Sep. 11, 2017, 8:09 PM), http://abcnews.go.com/US/hurricanes-harvey-irma-cost-us-economy-290-billion/story?id=49761970; Arelis R. Hernandez et al., *SinLuz Life Without Power*, Washington Post (Dec. 14, 2017), https://www.washingtonpost.com/graphics/2017/national/puerto-rico-life-without-power/.

6 Ivan Penn, *Power Lines and Electrical Equipment are a Leading Cause of California Wildfires*, Los Angeles Times (Oct. 17, 2017, 2:05 PM), http://beta.latimes.com/business/la-fi-utility-wildfires-20171017-story.html

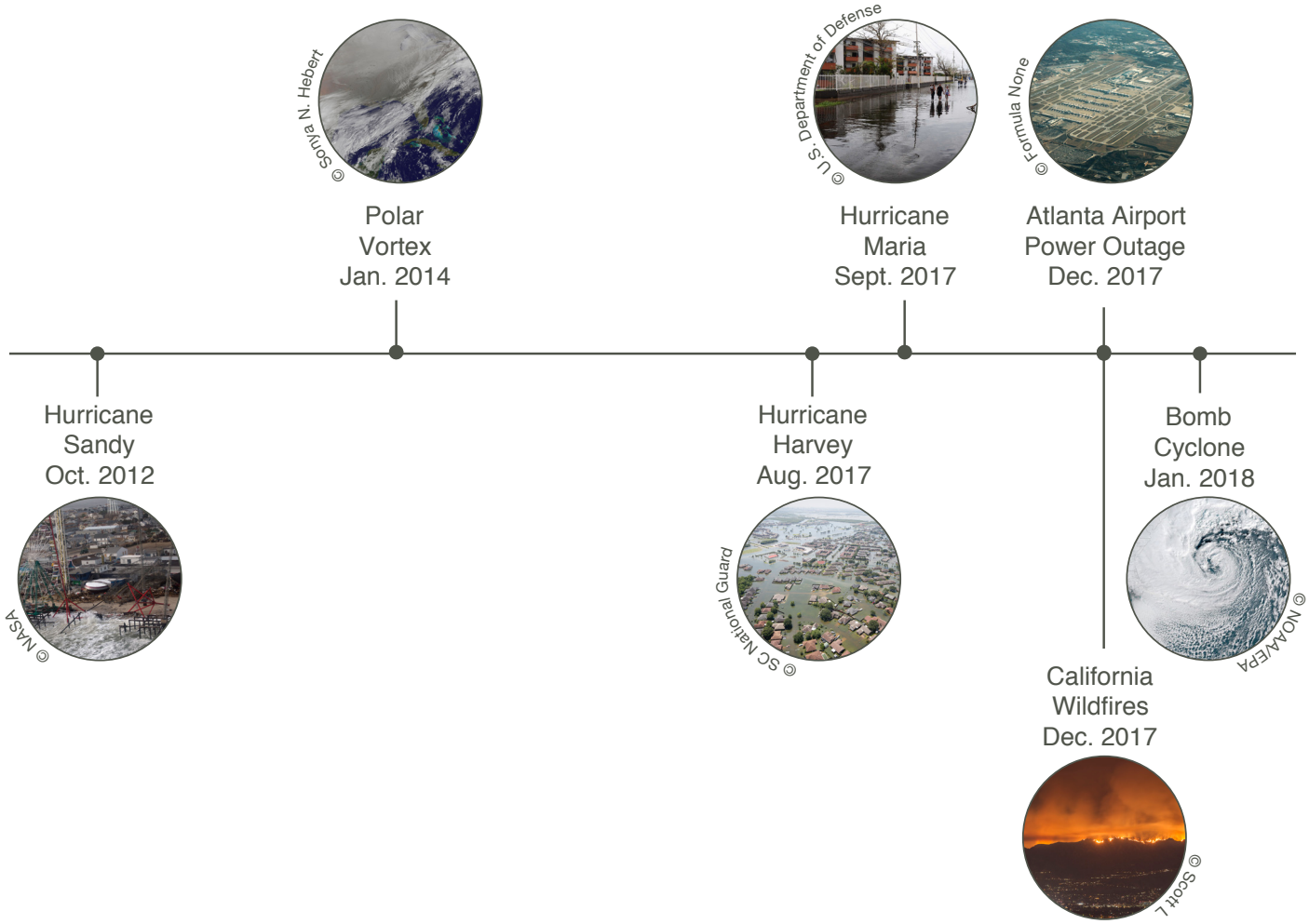
7 Michael Riley et al., *Russians Are Suspects in Nuclear Site Hackings, Sources Say,* Bloomberg (last updated July 7, 2017, 2:55 AM), https://www.bloomberg.com/news/articles/2017-07-07/russians-are-said-to-be-suspects-in-hacks-involving-nuclear-site.

8 Taylor Barnes & Jacey Fortin, *Power Failure at Atlanta Airport Snarls Air Traffic Nationwide,* NY Times (Dec. 17, 2017), https://www.nytimes.com/2017/12/17/us/atlanta-airport-power-out.html?hp&action=click&pgtype=Homepage&clickSource=story-heading&module=first-column-region&region=top-news&WT.nav=top-news.

9 *Grid Resiliency Pricing Rule*, 82 Fed. Reg. 46,940 (Oct. 10, 2017) [hereinafter "DOE NOPR"].

10 *Grid Reliability and Resilience Pricing, Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures*, 162 FERC ¶ 61,012 (Jan. 8, 2018) [hereinafter "FERC Resilience Order"].

Timeline of recent resilience threats



nuclear plants, asserting that planned retirements present national security concerns by "impacting the resilience of our power grid," which is used by military installations and defense-critical infrastructure.[11]

Recent events—particularly the devastation brought by long-term blackouts in Puerto Rico caused by Hurricane Maria in September 2017—have shown how damaging sustained power outages can be for U.S. citizens. And, while the DOE resilience proposal and the presidential order to DOE to keep coal and nuclear plants operational have been the subject of widespread criticism,[12] good-faith efforts to understand and improve the resilience of the electric grid at the local, state, regional, and federal levels are critical to the United States' continued prosperity.

If DOE, FERC, state and local governments, utilities, and grid operators are interested in truly improving resilience, they have many potential options. The process will require a systematic and considered focus; economic investment by ratepayers, utilities, and governments; and sustained and deliberate coordination and planning between utilities, grid operators, and regulators.

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[11] Brad Plumer, *Trump Orders a Lifeline for Struggling Coal and Nuclear Plants*, NY Times (June 1, 2018), https://www.nytimes.com/2018/06/01/climate/trump-coal-nuclear-power.html.

[12] Jeff St. John, *Behind the Backlash to Energy Secretary Rick Perry's Demand for Coal-Nuclear Market Intervention*, Greentech Media (Oct. 5, 2017), https://www.greentechmedia.com/articles/read/behind-the-backlash-to-energy-secretary-rick-perrys-demand-for-coal-nuclear; Gavin Bade, *How Trump's 'Soviet-style' Coal Directive Would Upend Power Markets*, Utility Dive (June 4, 2018), https://www.utilitydive.com/news/how-trumps-soviet-style-coal-directive-would-upend-power-markets/524906/.

Resilience is a wide-ranging and potentially amorphous concept. A variety of actions can help the grid defend against, absorb, or recover from high-impact, low-probability shocks; however, many potential actions that do so come at substantial cost. For example, it is expensive to harden existing systems (that is, make the system more resistant to potential physical disruption) or build infrastructure that is needed only if existing infrastructure fails or is destroyed. In some cases, those costs may exceed the benefits of avoiding or quickly recovering from grid outages, and making such investments would not be beneficial to society. Therefore, the cost of resilience-enhancing actions, and their expected impact on the probabilities and consequences of grid outages are critical to evaluating whether an action is worthwhile from an economic efficiency perspective. Ensuring that we make only efficient and cost-beneficial investments will require a clear and useable definition of resilience, categorization of attributes that improve resilience, and economic analysis of the social value of those attributes. Only by engaging in this type of analysis can policymakers ensure that they do more than simply pick winners based on political preferences.

This report aims to assist policymakers in understanding grid resilience and evaluating potential interventions aimed at improving it. The report first provides a definition of resilience grounded in academic literature. It then outlines a framework to identify socially optimal resilience investments. Next it outlines the authorities that states and federal agencies have for improving grid resilience, consistent with the jurisdictional divides established by the Federal Power Act. Finally, it applies the insights developed throughout the report to recent proposals from the Trump Administration to provide financial support to coal and nuclear generators based on asserted resilience attributes.

Key Institutions with a Role in Grid Resilience

State Public Utility Commissions - State regulators, commonly called "public utility commissions" or "public service commissions," are responsible for regulating local distribution utilities, setting retail electricity rates, and deciding on other state-level policies, such as distributed energy compensation, renewable portfolio standards, and energy efficiency programs.

Federal Energy Regulatory Commission (FERC) - FERC is a federal regulatory agency responsible for ensuring just and reasonable rates for wholesale electricity and interstate transmission. It maintains the authority to regulate the market rules implemented by operators of wholesale electricity markets. FERC is also responsible for ensuring reliable operation of the bulk power system—the system of large electric generators and high-voltage transmission lines.

Department of Energy (DOE) - DOE plays a limited role in resilience. Its primary electric-system responsibilities consist of analysis, funding new technologies, issuing regulatory proposals for FERC's consideration, and ordering specific actions in the case of electric-system emergencies.

National Electric Reliability Corporation (NERC) - NERC is a non-profit corporation designated by FERC to ensure reliable operation of the bulk power system. NERC collects information on power system outages, conducts reliability analyses, and develops and enforces reliability standards.

Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs) - ISOs/RTOs operate the wholesale electric system in two-thirds of the country, including operating competitive electricity markets. ISOs/RTOs ensure that supply and demand of the bulk power system are balanced using complex economic and engineering algorithms that take into account the location of both generators and demand, the costs of generation, and congestion in the transmission system. ISO/RTO-operated markets are also responsible for regional analysis, planning, and coordination of transmission and reliability.

Understanding Resilience

In order to improve electric system resilience, it is necessary to first have a common understanding of resilience, including what resilience is and how to measure it. This section starts with the basics, including the definition of resilience and how to measure it, and puts those concepts together into a useful conceptual model. It then draws implications of these concepts to give more nuance and provide a deeper understanding of grid resilience.

The Basics: Defining and Measuring Electric System Resilience

Defining Electric System Resilience

The concept of "system resilience" originates in the academic literature on ecological systems. Here, resilience was first defined as "a measure of systems and of their abilities to absorb change and disturbance and still maintain the same relationships between populations or state variables."[13] Since then, this concept has been applied to a variety of contexts and so has been incorporated into system planning across many disciplines. While the specific definition in each discipline varies, all definitions consider **the ability of a system to resist, absorb and adapt, and recover after an external high-impact, low-probability shock.**[14]

Over the last decade, a number of government entities have developed definitions of resilience for U.S. infrastructure in general, and for the electric system in particular.[15] These definitions have been broadly consistent with the academic literature and with each other. In its order rejecting DOE's resilience proposal and initiating a new proceeding to consider resilience in ISO/RTO markets, FERC synthesized these different efforts to arrive at a useable definition of resilience as

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[13] C. S. Holling, *Resilience and Stability of Ecological Systems*, 4 Ann. Rev. Ecol. Syst. 1, 14 (1979).

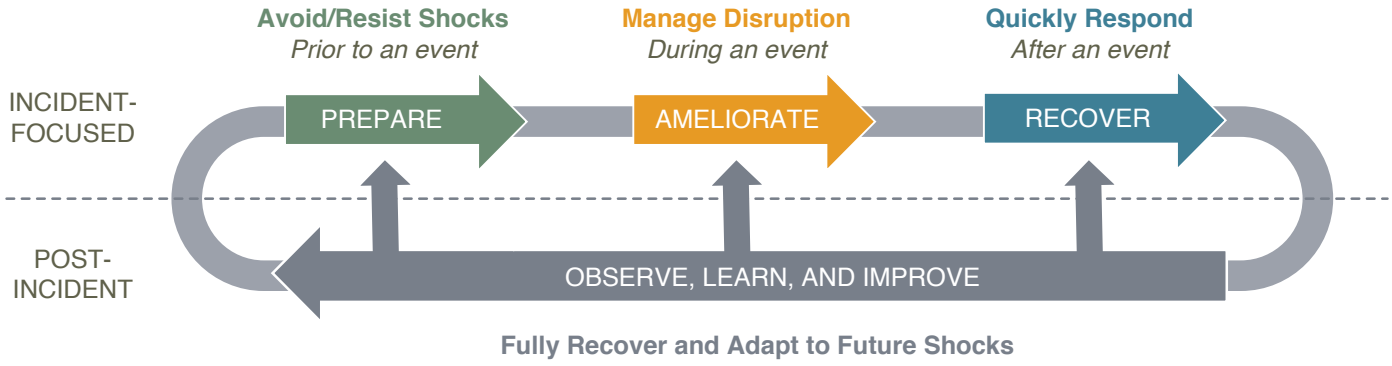
[14] Mathaios Panteli & Pierluigi Mancarella, *The Grid: Stronger, Bigger, Smarter?*, IEEE Power Energy Mag., May–June 2015, at 58, http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=7091066; Min Ouyang & Leonardo Dueñas-Osorio, *Multi-dimensional Hurricane Resilience Assessment of Electric Power Systems*, 48 Struct. Saf. 15, 15–24 (2014), http://dx.doi.org/10.1016/j.strusafe.2014.01.001; Eric Vugrin et al., Sandia Nat'l Labs., Resilience Metrics for the Electric Power System: A Performance-Based Approach (2017), http://prod.sandia.gov/techlib/access-control.cgi/2017/171493.pdf; Dep't of Energy, Transforming the Nation's Electricity System: the Second Installment of the Quadrennial Energy Review 4–3 (2017), https://energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf [hereinafter "DOE QER"]; Henry H. Willis & Kathleen Loa, RAND Corp., Measuring the Resilience of Energy Distribution Systems, 1–25 (2015); Cen Nan & Giovanni Sansavini, *A Quantitative Method for Assessing Resilience of Interdependent Infrastructures*, 157 Reliabity Engineering & Sys. Safety 35 (2017), http://dx.doi.org/10.1016/j.ress.2016.08.013; Dep't of Energy, Staff Report on Electricity Markets and Reliability 63 (2017), https://energy.gov/sites/prod/files/2017/08/f36/Staff Report on Electricity Markets and Reliability_0.pdf [hereinafter "DOE Staff Report"].

[15] In 2013, President Obama signed Presidential Policy Directive/PPD 21: Critical Infrastructure Security and Resilience, which establishes national policy on critical infrastructure security and resilience. PPD 21 defines resilience of critical infrastructure (including the electric system) as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions." Presidential Policy Directive/PPD-21, *Critical Infrastructure Security and Resilience*, The White House (Feb. 12, 2013), https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil [hereinafeter "PPD-21"]. This definition was echoed by DOE in the Second Installment of the Quadrennial Energy Review, a comprehensive analysis of trends and set of recommendations for modernizing the nation's electricity system to lower costs, reduce environmental effects, ensure reliable access to electricity. DOE QER at 4-4 (defining residence as "the ability to prepare for and adapt to changing conditions, as well as the ability to withstand and recover rapidly from disruptions, whether deliberate, accidental, or naturally occurring.")
The National Academy of Sciences defines resilience as encompassing a process for "lessen[ing] the likelihood that [electricity] outages will occur" and "coping with outage events as they occur to lessen their impacts, regrouping quickly and efficiently once an event ends, and learning to better deal with other events in the future." NAS at 10.

it relates to the electric system: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recovery from such an event."[16]

The characteristics highlighted in the FERC definition can be divided into a four-part framework developed by the National Infrastructure Advisory Council. A resilient electric system is able to: (1) avoid or resist shocks, (2) manage disruption, (3) quickly respond to a shock that occurs, and (4) fully recover and adapt to future shocks. In its 2017 report *Enhancing the Resilience of the Nation's Electricity System*, the National Academy of Sciences adopted this framework and developed a useful graphic for visualizing it, presented in Figure 1.

Figure 1: Four-part framework for conceptualizing resilience



Adapted from: Nat'l Acad. of Sci., Eng'g & Med., Enhancing the Resilience of the Nation's Electricity System 11 (2017), https://www.nap.edu/catalog/24836 .

Measuring Resilience

Resilience must be measured in order for policymakers and utilities to understand the electric system's current level of resilience, and evaluate potential interventions aimed at improving it. This requires a set of consistent resilience "metrics."[17]

The most useful type of resilience metrics are "performance-based." Performance-based metrics use quantitative data on either electric-system performance or the consequences of non-performance in the event of a high-impact, low-probability disruptive event.[18] These metrics can be based on the direct or indirect consequences resulting from such an event, depending on the goals and concerns of policymakers and grid operators. For example, a metric may focus on the direct consequences of a disruption to the generation, transmission, or distribution of electricity, such as the amount of energy services delivered to customers or the percentage of critical-customer energy demand served.[19] Alternatively, a performance-based metric may focus on indirect consequences or broader social perspectives, such as the availability of critical services that are at risk in the event of electric system outages (such as a potable water supply) or the general level of economic activity.[20]

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[16] FERC Resilience Order, 162 FERC ¶ 61,012 at P 23.
[17] Panteli & Mancarella at 59; Nan & Sansavini at 38.
[18] Vugrin at 13.
[19] *Id.* at 19-20.
[20] *See* Watson.

A Less Useful Alternative Approach: Attribute-Based Resilience Metrics

Attribute-based resilience metrics are an alternative to performance-based metrics.[21] Attribute-based metrics identify properties of systems generally thought to be resilient and categorize the extent to which an evaluated system possesses those properties, using expert surveys. The political discussion surrounding grid resilience has focused on system attributes—e.g., number of generators with on-site fuel, whether a system is an islanded micro-grid—rather than performance measurements.

Argonne National Laboratory has developed an attribute-based methodology for grading the resilience of critical infrastructure, which can be applied to the electric grid.[22] Table 1 provides examples of electric-system attributes that can contribute to resilience for each resilience characteristic discussed in the four-part framework.

Table 1: Example Attributes of Resilient Systems, by Characteristic[23]

Avoid/Resist	Manage	Respond	Recover/Adapt
Deployment of Advance Warning Technologies	Fuel Security including Fuel-less Resources, Fuel Storage, Availability of Fuel Delivery Infrastructure	Ability to Reroute Around Damaged Resources	Ease of Coordination
Hardened/Weatherized	Ability to Separate/Island	Available Substitute Resources	Investment
Regular Maintenance/ Vegetation Management	Ability to Load Shed or Ration	Stockpiled Replacement Resources	Process for Learning from Past Failures
Quantity of Resources Available	Redundant Resources		Number of / Magnitude of Mutual Aid Agreements

For each attribute, a system or component is assigned a numeric score. For example, a distribution system with underground wires may be assigned a high "hardened" score, and each identified attribute can be similarly categorized. This data is then aggregated into a numerical resilience score using subjective weighting and simple arithmetic.

Attribute-based metrics may be appealing because they require less data collection than performance-based metrics, and they may be more easily understandable for casual observers. However, these metrics are more subjective, creating risks that improvements to the attribute will not translate into measurable or predictable improvements in resilience. For example, recent political discussion has focused on "fuel security" as a critical resilience attribute, but a recent analysis of the 2018 cold weather event known as the "bomb cyclone" concluded that coal units had higher forced outage rates than natural gas units, despite the fact that coal units are generally thought to have higher "fuel security" attributes than gas units.[24] In addition, attribute-based metrics, particularly when evaluated one-by-one, are less useful than performance-based metrics for accurately measuring changes in system resilience. For example, a system that is incredibly hardened but lacks redundancy, warning systems, and regular maintenance would be fragile. While a system with a moderate amount of each might be quite resilient.

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[21] Vurgin at 12-13.

[22] F.D. Petit, et al., Argonne Nat'l Lab., Resilience Measurement Index: An Indicator of Critical Infrastructure Resilience (2013), http://www.ipd.anl.gov/anlpubs/2013/07/76797.pdf.

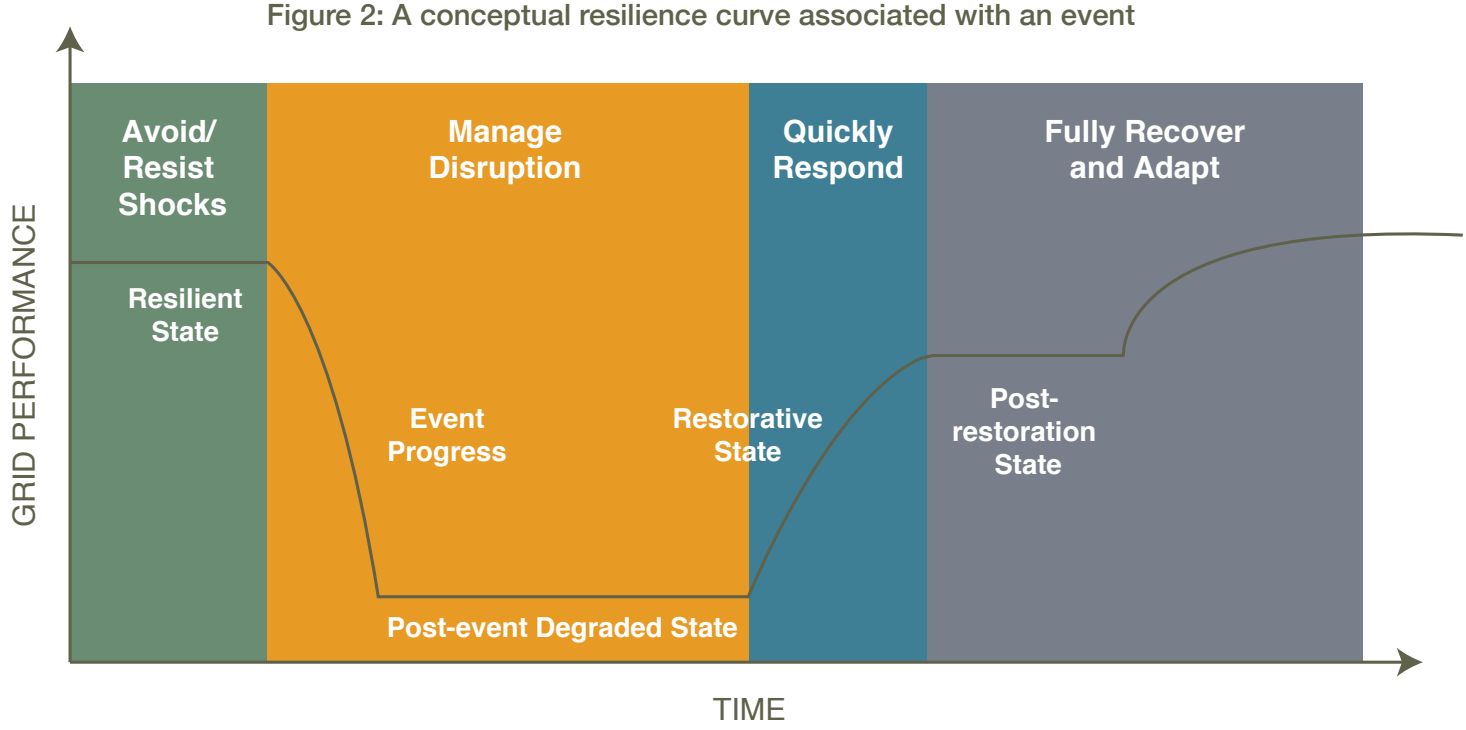
[23] This table is adapted from Watson at 29.

[24] PJM Interconnection, Strengthening Reliability: An Analysis of Capacity Performance (2018), http://pjm.com/-/media/library/reports-notices/capacity-performance/20180620-capacity-performance-analysis.ashx?la=en.

Putting it Together: The Phases of Electric System Resilience

The four characteristics of a resilient electric system outlined above can be conceptualized as four distinct phases of resilience in the event of a high-impact, low-probability shock, with different metrics and appropriate policy responses applied at each phase. Figure 2 shows a conceptual resilience curve that outlines the phases of resilience before, during, and after a high-impact, low-probability shock. In Figure 2, the vertical axis represents the performance of the system across time, before and after a high-impact, low-probability event.[25]

Figure 2: A conceptual resilience curve associated with an event



Adapted from: Mathaios Panteli & P Mancarella, *The Grid: Stronger, Bigger, Smarter?*, IEEE Power Energy Mag., 59 (2015)

This conceptual graph illustrates that the performance of the system, as measured by the chosen metric, will change over time as the system encounters each phase and exhibits the characteristics of resilience: the ability to (1) resist shocks when an event occurs, (2) manage shocks that disrupt the system, (3) respond to shocks by getting basic systems and services back online, and (4) fully recover from the shock and adapt for the future.

(1) The green area demonstrates an initial level of system performance in the period before an external shock. At this stage, the system's resilience depends on the capability of the system to **prevent and resist any possible hazards, and to reduce the initial damage if a hazard occurs**.[26] During this period, any resource or action that can reduce the probability of a high-impact, low-probability event or any initial damage would improve resilience. For example, when evaluating resilience in the face of a Category-5 hurricane, storm hardening efforts currently underway in many states reduce the probability of outages and increase the grid's ability to resist damage during the hurricane, increasing resilience. As another example, powering down nuclear plants in preparation for a hurricane can help prevent damage and ensure they remain available to provide electricity after the hurricane.

[25] Panteli & Mancarella at 59; Cen Nan & Giovanni Sansavini at 38.
[26] Panteli & Mancarella at 60.

(2) Once the high-impact, low-probability event happens, the system starts degrading (as illustrated in the orange area). At this stage, the system's resilience depends on the operational flexibility and resourcefulness of the system (and its operators) to quickly **manage evolving conditions and reduce the consequence of the event**.[27] During this period, any resource or action that can reduce the level of degradation or slow the system's degradation can improve resilience. For example, in the context of a hurricane, islanding microgrids can help reduce outages during the storm by minimizing the extent to which a single point of failure in the transmission or distribution system knocks out power for critical services, such as hospitals.

(3) Once the event ends, the system enters into a restorative/recovery mode (as represented in the blue area). At this stage, the system's resilience depends on whether it has a capacity to **enable a fast response** and on the amount of time required to repair the damages.[28] During this period, any technology or action that can expedite the recovery process would improve resilience. This is when on-site fuel can play a limited role in the event of a hurricane that has disrupted fuel transportation networks, such as pipelines. But, as the Puerto Rican grid's incredibly slow recovery from Hurricane Maria illustrates, the recovery capabilities of transmission and distribution generally serve as a bottleneck to power restoration and so tend to be far more important than generator resilience.

(4) Finally, the system enters into a post-restoration state and then an **infrastructure recovery period** (as represented in the grey area).[29] Whether the system can return to its initial resilience level depends on the severity of the event and the level of improvement and investment made in restoration.[30] While the system may return to normal operation during phase (3), full infrastructure recovery may take longer. For example, power may be restored quickly after a flood, even though replacing all the damaged equipment may take longer.[31] During this period, any technology or action that can reduce the time to fully recover would improve resilience. On the other hand, during this phase, the steady-state level of performance can exceed the level preceding the event if, for example, policymakers and grid operators operationalize lessons learned from the event or make investments that minimize risks of future events or of the magnitude of damage.

The transition times shown in Figure 2 are as important as the levels of the performance metric in characterizing the system's resilience.[32] It is important not only to minimize the consequence of, and hence the losses resulting from, the event but also to *ensure that the system degradation occurs slowly* and that *recovery occurs quickly*.[33]

Deepening Understanding: Grid Resilience Insights

A number of implications flow from this framework. First, resilience is a long-term, ongoing, and adaptive concept. Resilience is not achieved, but only improved. Second, resilience is about more than avoiding outages. A resilient electric system minimizes the frequency of unexpected post-shock outages. But even a resilient electric system can experience outages in the face of a high-impact shock. When outages occur, a resilient system is one that manages the consequences of outage events and recovers quickly.[34]

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[27] *Id.*
[28] *Id.*
[29] *Id.*
[30] *Id.*
[31] *Id.*
[32] *Id.*
[33] *Id.*
[34] NAS at 10.

In addition, the definitions and measures of resilience suggest three larger implications:

- Resilience should be evaluated with respect to the full electric system, not just of individual components;
- Resilience should be defined and measured with respect to specific threats; and,
- Resilience and reliability are distinct concepts with different metrics.

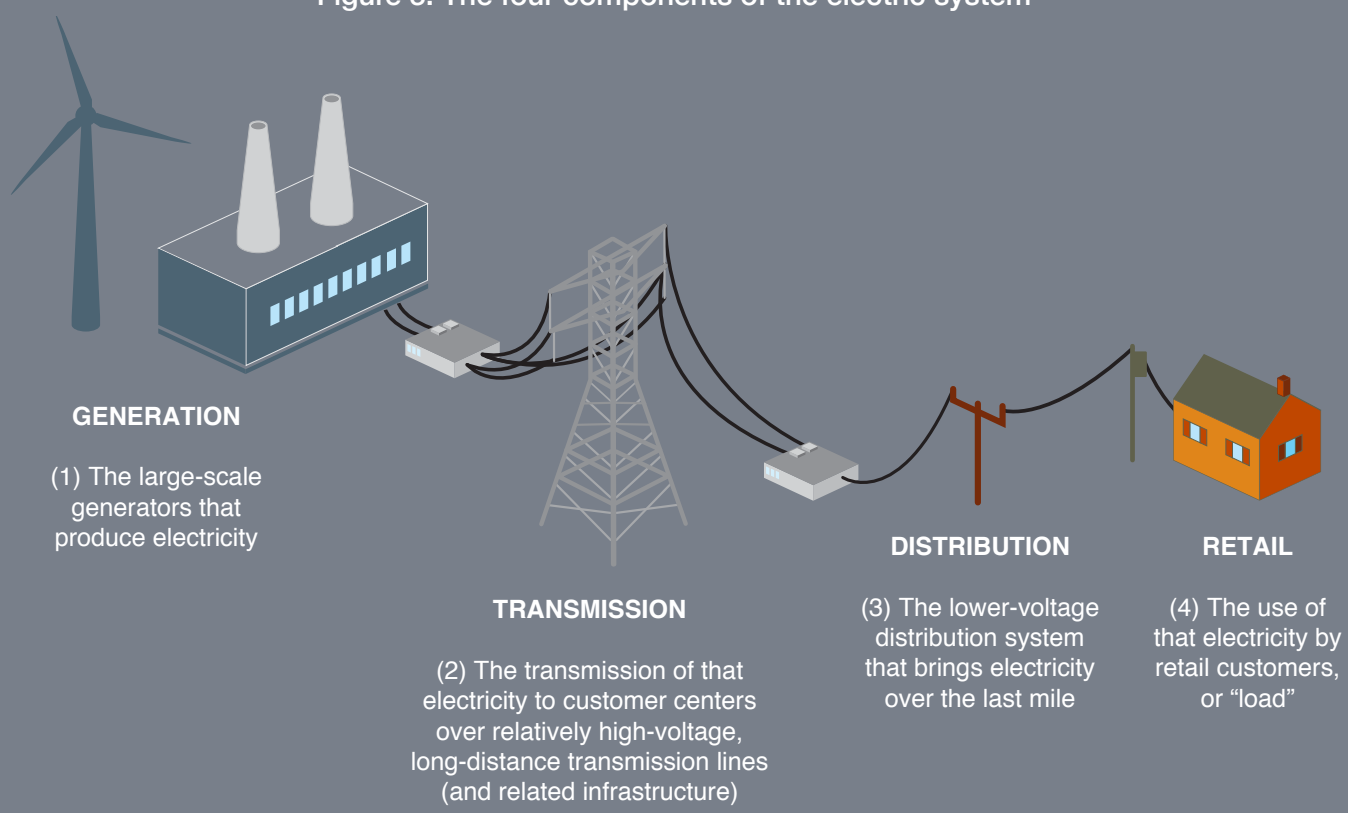
These are discussed in turn.

Resilience Should Be Evaluated with Respect to the Full Electric System

Individual components of the electric system may be vulnerable to high-impact, low-probability external shocks. Poorly maintained distribution infrastructure can cause or be disrupted by fire; a generating plant managed by poorly trained staff may be unprepared for a hurricane, resulting in permanent damage. In some cases, investments and policies that address the identified vulnerabilities of individual components in the electric system can enhance overall system resilience. This type of component-by-component resilience analysis can be characterized as:

- Generation resilience
- Transmission resilience
- Distribution resilience

Figure 3: The four components of the electric system



But resilience is not merely a sum-of-its-parts concept. Individually measuring or improving the resilience of each system component will not necessarily improve the resilience of the entire system. For example, significant investment in generator weatherization may do relatively little to reduce customer outages in the face of a Category 5 hurricane if distribution systems are not also hardened. In fact, interventions that improve the resilience of one system component can reduce the resilience of another, mitigating, and potentially reversing, improvements to system resilience. For example, subsidizing a large centralized generator with on-site fuel in order to mitigate the potential for outages caused by fuel-delivery disruption can increase the consequences of a physical attack on the transmission infrastructure that supports the centralized generator. The net effect of resilience improvements will depend on the relative probabilities of potential high-impact shocks, and the interactions of system components in the face of such shocks.

Therefore, in addition to evaluating whether a particular intervention is economically justified with respect to the appropriate component, regulators, grid planners, and utilities should evaluate the effect of the intervention on the electricity system as a whole. We refer to that concept as "system resilience."

Resilience Should Be Defined and Measured with Respect to Specific Threats

The electric system faces a wide variety of potential high-impact, low-probability shocks that can cause significant customer outages. Relevant threats may include extreme weather (hurricanes, tornadoes, wildfires, drought, extreme cold); sea level rise caused by climate change; other natural events, such as earthquakes and tsunamis; targeted physical attacks on electric infrastructure; cyberattacks; severe geomagnetic disturbances; and electromagnetic pulse events.[35]

Potential Significant Causes of Electricity System Outages		
Extreme Weather Event	**Human-Caused Event**	**Other**
Drought and water shortage Earthquake Flood and storm surge Hurricane Ice storm Tornado Tsunami	Cyberattack Physical attack Intentional electromagnetic pulse Major operation error	Volcanic event Space-based electromagnetic event Fuel supply disruption

Adapted from: Nat'l Acad. of Sci., Eng'g & Med., Enhancing the Resilience of the Nation's Electricity System, 50-69 (2017).

There is no overarching metric of resilience relevant for all known and unknown high-impact, low-probability disruptions; rather, the resilience of a system to one threat will likely be different from resilience to other threats. This is because the magnitude of vulnerability to one threat does not imply similar vulnerability to other threats. A system with weak cybersecurity defenses may have excellent physical security that protects against physical attacks. In addition, the risk of extended outages from different threats may even be inversely related; that is, actions taken in the name of grid resilience may improve the ability of the system to resist or recover from certain disruptive events yet undermine its ability to resist or recover from others. For example, putting wires underground may improve resilience against hurricane-force winds

[35] EPRI, Electric Power System Resiliency: Challenges and Opportunities 6-8 (2016), https://www.naseo.org/Data/Sites/1/resiliency-white-paper.pdf [hereinafter "EPRI"].

but may reduce resilience against earthquakes. Ensuring available on-site fuel may make the grid resilient to fuel-supply disruption but may expose the create new grid vulnerabilities related to significant flooding,[36] leakage,[37] or temperature variations that make stored fuel unusable.[38]

These differences mean that policymakers must prioritize threats. Because resilience focuses on low-probability events, "making every corner of our utility systems resistant to failure would prove cost-prohibitive."[39] Measures to improve electric system resilience should be undertaken selectively to address the specific threats that pose the greatest risk for a given geographic area and electric system component.

Resilience and Reliability are Distinct Concepts with Different Metrics

The definition of resilience is different from the related and often conflated concept of "grid reliability." NERC defines reliability to include two concepts:

- "Operational reliability" is the ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts; whereas
- "Resource adequacy" is the ability of the electric system to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages.[40]

Whereas resilience is concerned with the ability of the system to prevent and recover quickly from outages caused by high-impact, low-probability events, reliability focuses on limiting the occurrence or spread of outages caused by (relatively) low-impact, high-probability events such as power surges and sudden increases in demand.[41] For example, a Category 5 hurricane that destroys substantial portions of the transmission and distribution system creates a resilience problem when it results in long-term electric system outages for a substantial number of customers until infrastructure can be replaced or rebuilt. On the other hand, an unexpected power surge on a distribution line may create a reliability problem by overloading a key circuit, causing some customers to lose power for a relatively short period. Reliability problems can become resilience problems to the extent that, if not properly managed, they result in cascading blackouts and destruction of infrastructure that requires substantial recovery operations.[42]

Reliability interventions generally seek to lessen the likelihood of outages. Resilience is similarly concerned with lessening the likelihood of disruptive but less-common events, but it also recognizes that disruption will likely occur in the case of

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[36] Mark Watson, *Harvey's Rain Caused Coal-to-Gas Switching: NRG Energy*, S&P Global Platts (Sept. 27, 2017, 5:22 PM), https://www.platts.com/latest-news/electric-power/houston/harveys-rain-caused-coal-to-gas-switching-nrg-21081527.

[37] Robert Walton, *CAISO Considers Making Aliso Canyon Gas Reliability Measures Permanent*, UtilityDive (June 8, 2017) https://www.utilitydive.com/news/caiso-considers-making-aliso-canyon-gas-reliability-measures-permanent/444522/

[38] N. Am. Elec. Reliability Corp., Polar Vortex Review 3 (2014); *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Winter 2013-2014 Operations and Market Performance in RTOs and ISOs*, 149 FERC ¶ 61145 at 8 (Apr. 1, 2014), https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf.

[39] Miles Keogh & Christina Cody, Nat'l Assoc. Reg. Util. Comm'rs, Resilience in Regulated Utilities 1 (2013), https://pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D.

[40] NERC, Frequently Asked Questions 1 (2013), https://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf (Operational reliability is also sometimes called "security").

[41] Panteli and Mancarella at 60; Vurgin at 8. Watson at 16.

[42] The 2003 Northeast blackout serves as a good example of a reliability problem that, left untreated, became a resilience problem. *See* FERC, Reliability Primer 31-32 (2016), https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf [hereafter "FERC Reliability Primer"].

a high-impact event. It therefore also focuses on establishing systems to manage and quickly recover from the disruption. As such, the National Academies of Sciences have concluded that "resilience is broader than reliability."[43]

As different (if related) concepts, resilience and reliability must be measured separately. Reliability is a static concept measured by well-defined and consistent metrics.[44] The two most frequently used metrics are measures of the *duration* of system outages (System Average Interruption Duration Index (SAIDI)) and the frequency of system outages (System Average Interruption Frequency Index (SAIFI)).[45]

However, these metrics are not generally appropriate for directing useful resilience decision making. They fail to consider that the impact of an interruption increases the longer the duration of the disruptive event.[46] And regulators often exclude major events when using these metrics because the effect of those events can swamp the smaller events that reliability interventions are generally created to address.[47] Because of the differences between the concepts, the metrics for reliability are not suitable for measuring resilience.[48]

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[43] NAS at 1.
[44] Panteli and Mancarella at 60; Vurgin at 8; Watson at 16.
[45] *See* Keogh at 6.
[46] *Id.* at 7-8.
[47] *Id.*
[48] *Id.* at 11-12.

Evaluating Resilience Interventions

Resilience of the grid to high-impact, low-probability events is a "public good." Public goods are typically underprovided by the market.[49] During a blackout, no generator is able to sell energy. As a result, when a resilience investment prevents or reduces the time of a blackout, all generators that would have sold power benefit. Similarly, given that no consumer can receive energy during a blackout, all consumers benefit from investments that forestall or mitigate a blackout, regardless of whether they pay directly for that service. Resilience investments made by utilities do not necessarily take into account all potential benefits to other entities, so they often will yield a sub-optimally low level of investment needed to facilitate the socially desirable level of resistance, management, response and recovery from high-impact, low-probability shocks. And, therefore, government must play a critical role in ensuring an efficient level of grid resilience.

One of the key challenges of an open-ended and multifaceted public good such as resilience is that regulators and utilities must determine the optimal level and type of resilience interventions. Resilience interventions could include physical improvements, such as hardening the distribution and transmission networks or weatherizing power plants;[50] operational improvements, such as using advanced awareness systems or adaptive islanding;[51] or increased deployment of distributed energy resources and microgrids.[52]

As discussed above, resilience is not binary; the grid is neither "resilient" nor "not resilient." Resilience exists on a spectrum. The grid can maintain different levels of resilience against different types of threats (weather, cyberattack, physical attack, geomagnetic disturbance) at different phases (resistance, continued operation, response, recovery). Improving any of these aspects requires the investment of time and resources; therefore, society must consider how much resilience is the appropriate amount.

Key Term: Public Good

A "public good" is a good or service that is non-rival and non-excludable. Non-rivalry means that the good or service being enjoyed by some does not prevent others from enjoying it simultaneously. Non-excludability means that it is not possible to prevent individuals from enjoying the benefits of the good or service even if they do not pay for it. Public goods are generally underprovided by the market because market participants cannot capture enough value individually to justify investing in the good at the socially efficient level. In order to ensure economically efficient levels of public goods, government intervention—such as direct investment, subsidy, or regulation—is necessary.

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[49] NAS at 14.

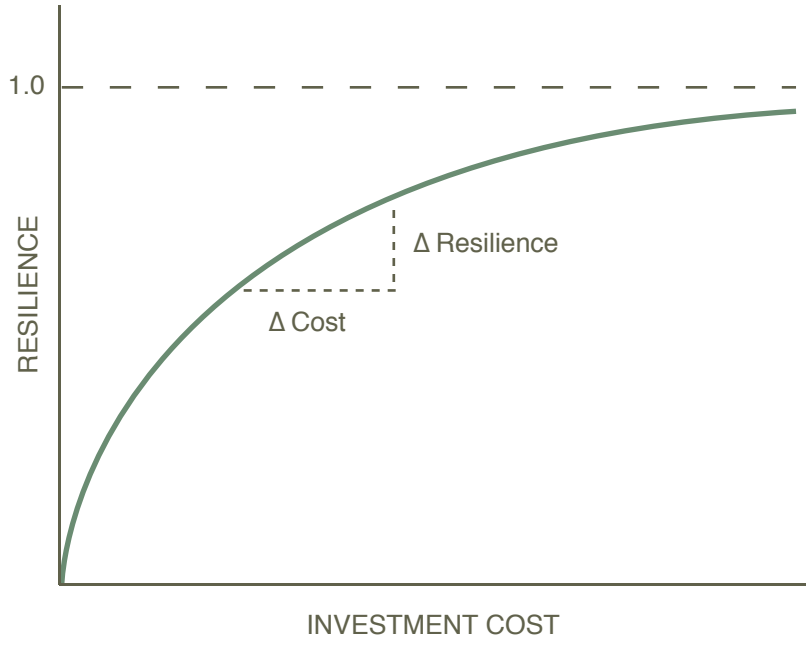
[50] Panteli and Mancarella at 60.

[51] Yi Ping Fang et al., *Resilience-Based Component Importance Measures for Critical Infrastructure Network Systems*, 65 IEEE Transactions on Reliability 502, 502–512 (2016), http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=7407429; Mathaios Panteli et al., *Boosting the Power Grid Resilience to Extreme Weather Events Using Defensive Islanding*, 7 IEEE Transactions on Smart Grid 2913, 2913–2922 (2016), http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=7407429; Eric D. Vugrin et al., *Optimal Recovery Sequencing for Enhanced Resilience and Service Restoration in Transportation Networks*, 10 Int. J. Critical Infrastructures 218 (2014), http://www.inderscience.com/link.php?id=66356.

[52] NAS at 77-78.

The tradeoff between a given level of resilience and the investment needed to achieve that level of resilience is conceptually represented in Figure 4. This figure shows that a change in investment (ΔCost) will yield a change in resilience (ΔResilience) and that a 100% level of resilience is not achievable.[53]

Figure 4: Incremental cost of resilience



Adapted from: Jean-Paul Watson et al., Sandia Nat'l Labs., Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States 53 (2015).

Also, because of the variety of threat types and potential interventions, resource allocation among threats and technological solutions is critical. Government entities and utilities, therefore, need a decision framework that helps them decide which investments or projects to improve resilience are worthwhile and which are not.

In the second installment of its Quadrennial Energy Review, DOE suggests that cost-benefit analysis should be used to evaluate resilience investments.[54] In its recent compliance filing in FERC's resilience docket, the California ISO also advocated using cost-benefit analysis to assess potential resilience interventions.[55]

Using cost-benefit analysis to evaluate resilience policies and investments has two main advantages:

- First, cost-benefit analysis can help policymakers and utilities develop policies and make investments that maximize social welfare. Investments are socially efficient when the incremental cost of achieving the level of resilience—that is, the last dollar needed to achieve a particular level of resilience—is equal to the incremental

[53] Engineers who study resilience represent the performance of a system over the course of an event using formulas where the resilience metrics span the range of 0 (lowest level of performance during an event) to 1 (return to steady-state level of resilience). Yi Ping Fang at 65. This is reflected as the Y-axis in Figure 4.

[54] DOE QER at 7-22.

[55] Comments of California Independent System Operator Corporation at 8, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 (March 9, 2018).

resilience benefit—that is, the benefit of the last "unit" of resilience achieved. When choosing among conflicting options, the efficient investment would maximize net benefits to society.[56] This approach can be used regardless of whether the investments will be made by government entities or by utilities at the direction of regulators.

- Second, evaluating potential policies and investments using a systematic and evidence-based framework can help to ensure that proposals are actually effective (and cost-effective) in enhancing resilience, rather than just pretext for providing financial support to favored industries. For example, policymakers can use cost-benefit analysis to evaluate whether proposals to limit retirement of coal and nuclear plants would achieve their goals of reducing the expected costs of a cyberattack on natural gas pipeline infrastructure and reducing outages at defense-critical facilities such as military bases. Such analysis is particularly important for policy proposals, such as this, which would impose substantial costs, upend electricity markets, and potentially fail to achieve resilience goals, according to substantial expert criticism.[57] Cost-benefit analysis can provide the public and courts a transparent basis to evaluate proposals to determine whether the means chosen to enhance resilience match the specific threats identified.

Conducting cost-benefit analysis requires an evaluation of the incremental benefits and incremental costs of various resilience-improving policies and investments. The rest of this section outlines methods for evaluating these benefits and costs, and then highlights examples of state policies and studies that have put similar methodologies into practice.

Incremental Benefits of Resilience Interventions

To determine the efficient level of different resilience policies or investments, decisionmakers must first understand the expected benefits of such actions. Resilience policies and investments are valuable because they allow society to avoid or mitigate costs that would be imposed by a high-impact, low-probability event. For example, an investment that reduces 1000 customer outage hours from a hurricane provides society with benefits equal to the economic value of avoiding those outage hours. Calculating the benefits of resilience investments and policies involves quantifying the probability-weighted costs of disruptions, and how those costs change based on the investments and policies being considered. Therefore, resilience benefits are a function of the probability of each particular high-impact, low-probability event; the social cost if the event were to occur; and the extent to which the investment reduces the event's probability or impact.

In this section, we lay out a streamlined version of a framework for calculating the benefits of resilience investments and policies that was developed by Sandia National Laboratory as part of the DOE Metrics Analysis for Grid Modernization Project.[58]

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[56] Office of Mgmt. & Budget, Circular A-4 at 10(Sept. 17, 2003), *available at* https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf [hereinafter "Circular A-4"].

[57] *The Electric Grid of the Future: Hearing Before the Energy Subcomm. of the H. Sci. Comm.* (2018) (testimony of Robert E. Gramlich President, Grid Strategies LLC), https://science.house.gov/sites/republicans.science.house.gov/files/documents/HHRG-115-SY20-WState-RGramlich-20180607.pdf.

[58] Vugrin. Sandia produced a useful example of how this framework can be used to evaluate the benefits of different resilience interventions, including investments in line-burying and flood walls, and policy responses such advanced planning in the event of a hurricane. *See* Wastson et al at 73-80.

Step 1: Characterize Threats

First, policymakers must identify and characterize the specific threats against which the system should be resilient; examples include a hurricane exceeding a specific category, earthquakes exceeding a certain magnitude, a cyberattack that disables physical infrastructure control systems (called "SCADA systems"), and extreme cold or heat for specified durations.

Selecting relevant threats for which the policymaker is responsible will involve a combination of judgment and probabilistic analysis about the events most likely to significantly disrupt the electric system. In many instances, the threats identified will differ by region. The benefit of protecting against hurricane-force winds is likely greater in Tampa than in Los Angeles, whereas the benefit of improving distribution system resilience with respect to wildfires or earthquakes may be greater in San Francisco than in Houston. The probability of human-caused threats, such as cyberattacks or physical security attacks, will differ by region—attacks are more likely in Paris, France than Paris, Texas. Moreover, due to higher population density and economic output, the magnitude of impact and therefore the benefit of an intervention may be greater in New York City than in Duluth.

This step involves not only the identification of types of disruptive events but also a detailed specification of threat scenarios against which resilience improvements will be measured (e.g., the magnitude and location of an earthquake along with the number and magnitude of aftershocks). These scenarios should include probability estimates for the threats, which will be incorporated into later steps.

Step 2: Define Resilience Metrics

Next, policymakers should define the specific resilience metrics that will be used to measure the existing level of system resilience given the threats identified in Step 1, and the potential level if investments or policy changes are made.

In order to be useful in quantitative analyses of resilience, metrics should be performance-based and have the following features:

- Measurable in terms of the *consequences* expected to result from particular threat types.
- Reflect uncertainty (e.g., the expected consequence or the probability of the consequence occurring exceeds an acceptable level).[59]
- Use data from computation models that incorporate historical experience or expert evaluation.

Metrics can be direct (e.g., the cumulative number of customers or hours without power after an event) or indirect (e.g., the number of critical services without power for more than the time they typically have backup power). These metrics should then be monetized for use in a holistic cost-benefit analysis, such as the cost of electric system repair and the economic value of lost load.

For example, in a study of how on-site renewable energy and storage systems can improve the resilience of electricity delivery to buildings in New York City, researchers at the National Renewable Energy Laboratory and the City University

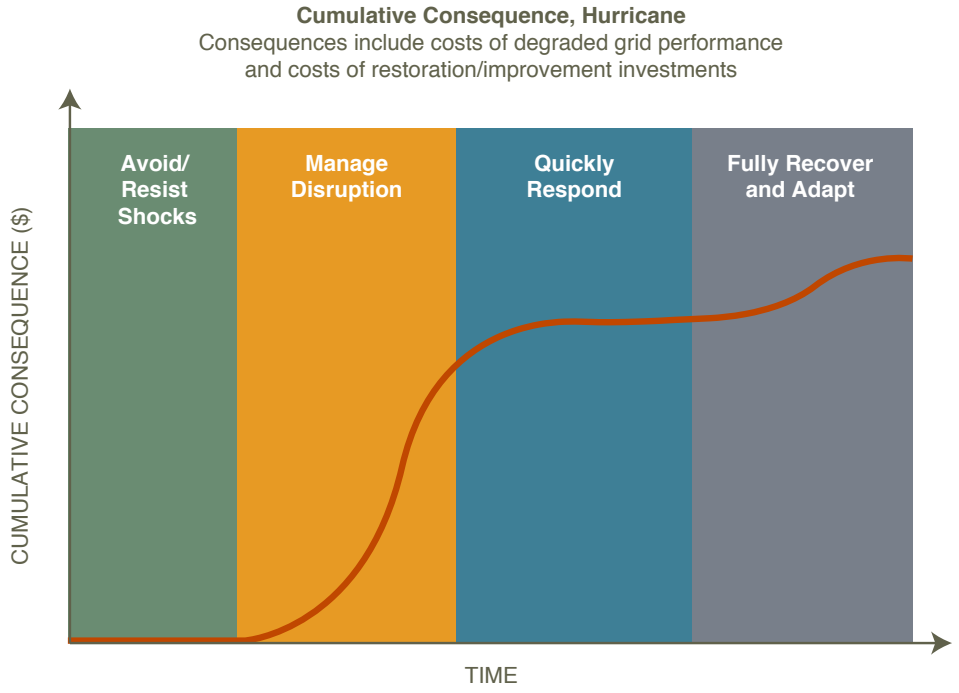
[59] Vugrin at 16-17.

of New York developed a resilience metric—the "value of resiliency."[60] This metric was calculated as the Value of Lost Load multiplied by the increased amount of "critical load" that could be served during a grid outage due to installation of on-site renewable energy and storage.[61]

Step 3: Quantify Baseline Resilience

This step involves the quantification of the baseline level of resilience—how the identified threats are expected to affect generation, transmission, distribution, and customer infrastructure, without any policy intervention. This specification can include which assets may be lost or degraded as well as repair/replacement time and cost. Ranges can be used to incorporate uncertainty. Policymakers and planners can then use system-level computer models to more fully evaluate the systemic effects of that infrastructure disruption. These simulations can facilitate calculation and quantification of the expected consequences of each hazard over time. These consequences should be expressed in terms of the monetized resilience metrics developed in Step 2. As illustrated in Figure 5 the lost economic value caused by power outages and the cost of infrastructure repair can be summed over time to produce a cumulative assessment of the consequences of a threat.

Figure 5: Calculating cumulative consequences of a threat



Adapted from: Jean-Paul Watson et al., Sandia Nat'l Labs., Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States 39 (2015).

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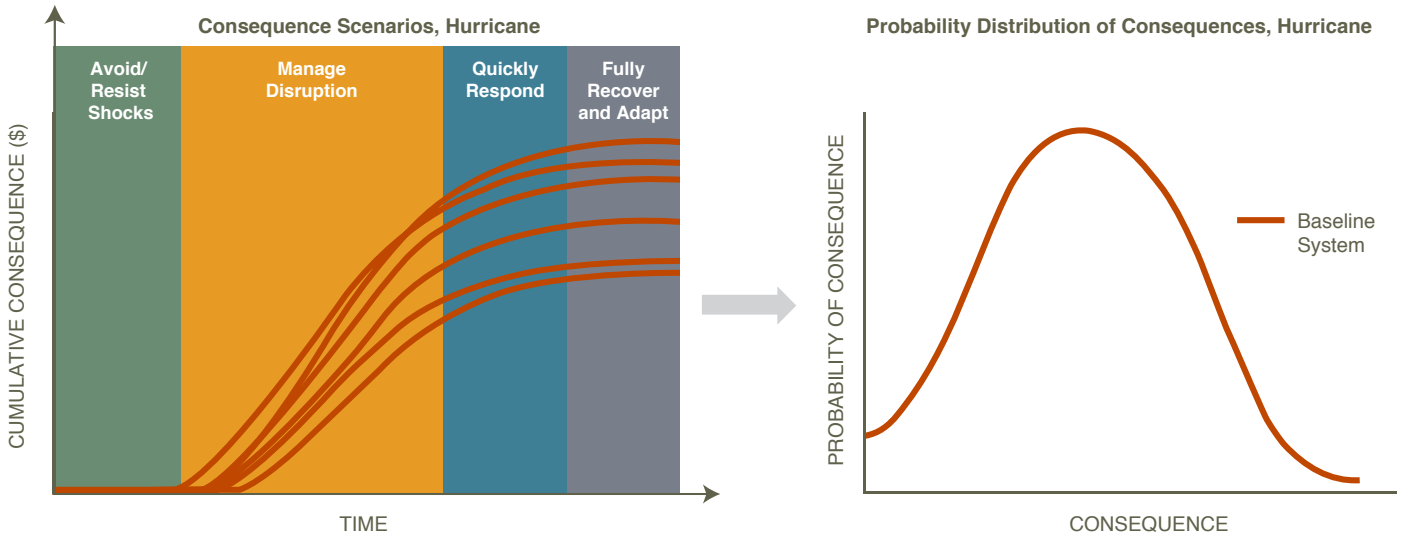
[60] *See* Kate Anderson et al., *Quantifying and Monetizing Renewable Energy Resiliency*, 10 Sustainability 933 (2018), http://www.mdpi.com/2071-1050/10/4/933/htm#B13-sustainability-10-00933.

[61] The researchers used a Value of Lost Load of $100 per kWh. Modeling showed that the renewable energy plus storage system under consideration would allow a building to sustain load for three times longer than a diesel backup generator; and so valued the resilience benefit of that system at $781,200. *Id.* § *See also The Interruption Cost Estimate Calculator 2.0*, ICE Calculator, https://icecalculator.com/home (last visited July 31, 2018) for an online tool developed by Lawrence Berkeley National Lab to estimate interruption costs or improvement benefits.

Because resilience is concerned with high-impact, low-probability events, it is important to take into account uncertainty in what level of disruption a given event will cause. In the baseline analysis, regulators can use the computer models to simulate different scenarios that reflect changes in threat significance or other key variables. These various simulations can be combined to produce a probabilistic value of the consequence of a threat. This is demonstrated in Figure 6.

Figure 6: Probabilistic Consequence of a Threat



Adapted from: Jean-Paul Watson et al., Sandia Nat'l Labs., Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States 39 (2015).

Step 4: Characterize Potential Resilience Interventions

Once the baseline resilience is identified, the goal is to calculate the value of resilience improvements achievable through particular interventions. These interventions could come in the form of mandated or direct investments in the generation, transmission, or distribution systems (such as fuel storage, hardening, or vegetation management), or they could be regulatory policies, such as requiring coordination among grid operators and utilities; changing market rules to provide market participants performance or investment incentives; or mandating specific actions, such as cybersecurity practices.

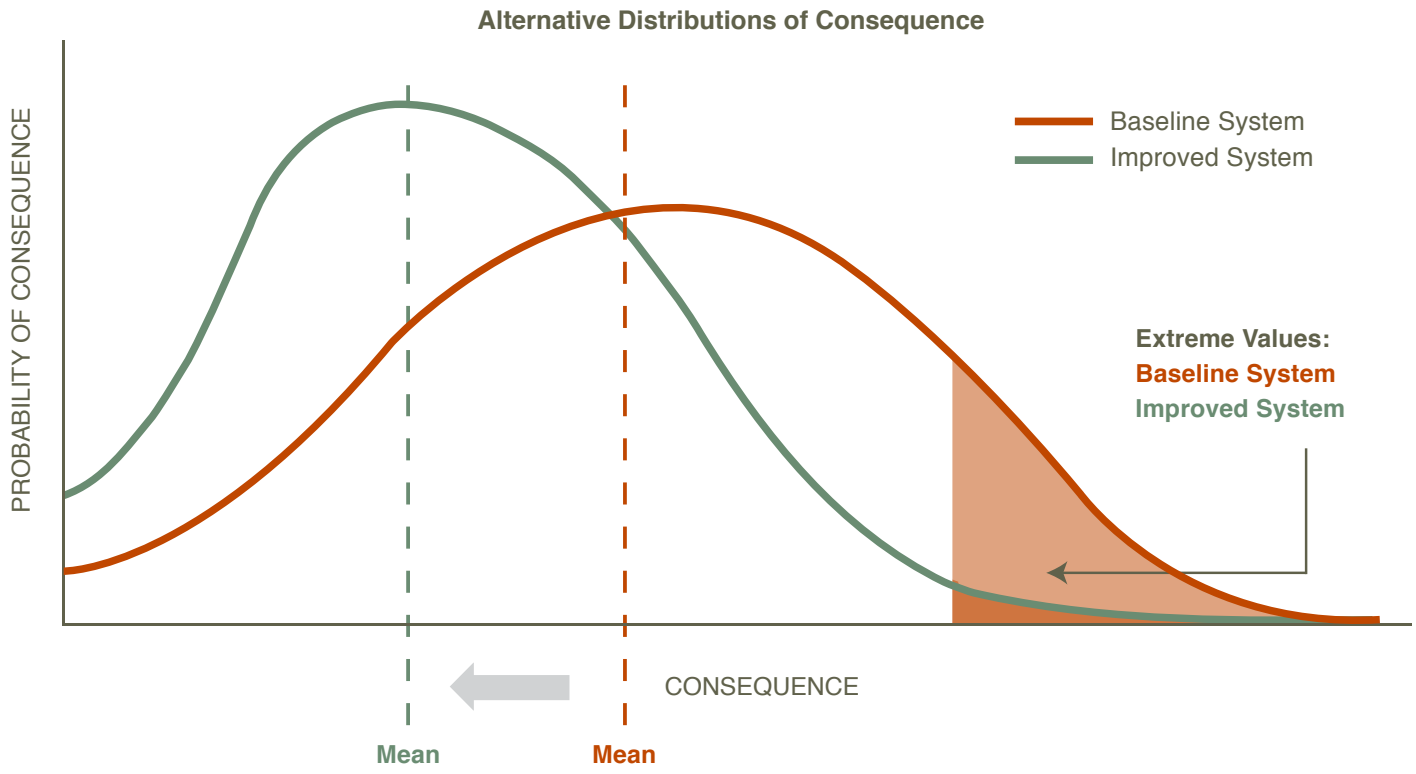
Once a menu of potential interventions is identified, the effects of interventions can be characterized. Some interventions enhance resilience by reducing the probability of specified threats. For example, strict password security protocols can reduce the likelihood that hackers penetrate utility control systems. While quantification of the change in threat probability of an event may be particularly difficult, policymakers can, nonetheless, make reasonable assumptions. Other interventions enhance resilience by reducing the magnitude of disruption that will occur in the face of identified threats. For example, an intervention might reduce the time needed to deploy new infrastructure by maintaining an infrastructure reserve or by facilitating islanding of a slice of the electric system to prevent cascading blackouts.

Step 5: Evaluate Resilience Improvements from Interventions

Evaluating the benefits of each potential intervention involves repeating Step 3, but with appropriate changes made to the electric system simulation models based on the particular policy or investment characterized in Step 4. The monetized savings between the baseline resilience metrics and the improved resilience metrics constitute the benefits of the intervention.

Figure 7 graphically demonstrates how a baseline level of resilience and resilience after an intervention can be compared.

Figure 7. Comparing resilience consequences of baseline and intervention scenarios.



Source: Jean-Paul Watson et al., Sandia Nat'l Labs., Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States 40 (2015).

Limitations

While this framework establishes a pathway for quantifying the benefits of resilience interventions, it carries substantial information requirements. This methodology requires understanding the probability distributions and likely damage functions of the underlying high-impact, low-probability events. We have limited information on these events due to their nature; incorporation of uncertainty into the analyses is therefore critical. In addition to quantifying baseline resilience, the methodology requires sufficient data to predict the extent to which investments and policies will change the probabilities and consequences of threats.

Incremental Costs of Resilience Interventions

There are a number of cost categories when evaluating potential resilience interventions. OMB Circular A-4 provides guidance to federal agencies regarding the estimation of costs and benefits of agency decisions and can serve as a useful guide for the consideration of the costs of resilience interventions.[62] Circular A-4 directs agencies to consider private-sector compliance costs, administrative costs, losses in consumer and producer surpluses, costs associated with countervailing risks, and health and safety costs.[63] Resilience investments and policies can impose costs in all of these categories.

Resilience investments and policies have direct, monetary costs on entities responsible for building or improving infrastructure. These may include project costs to improve or harden existing electric system infrastructure, build new transmission or distribution lines, or stockpile components; investments in cybersecurity and physical security; and costs related to planning or coordination exercises.

Policies that improve resilience by changing market rules can also result in additional consumer costs through increases in the price of electric energy and capacity. Because of the complex relationship between firm and consumer behavior affected by market rule changes, calculation of these costs may require the use of power sector and electric market modeling.

Resilience interventions can entail additional costs related to increases in countervailing risks. Interventions that improve resilience of one phase (resistance, continued operation, response, or recovery) may ultimately undermine the resilience of another phase. For example, putting transmission lines underground may significantly improve the resistance of transmission to disruption, but it will also make recovery more difficult if disruption occurs (e.g., due to flooding). As such, regulators and utilities should also evaluate an intervention's associated trade-offs, and the total effect on electric system resilience across phases. Costs associated with countervailing resilience risks can be calculated using the framework outlined above.

Some resilience interventions may also have environmental costs. Policy changes and infrastructure investments can alter the incentives to operate various power plants with different environmental performance, such as different rates of air pollution emissions. Similarly, investments in new infrastructure can result in environmental impacts associated with project development. These environmental effects can be quantified and monetized as environmental costs.

Relevant Examples from States

While methodologies to quantify the costs and benefits of resilience improvements have not been widely used in regulatory proceedings, there are some recent examples that can serve as a basis for policymakers.

New York State discusses a methodology for quantifying resilience benefits in the Benefit-Cost Analysis Framework associated with the state's Reforming Energy Vision proceeding.[64] Utilities use the Benefit-Cost Analysis Framework

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[62] *See* Circular A-4.

[63] *Id.* at 26, 28, 37.

[64] Order Establishing the Benefit Cost Analysis Framework, Case No. 14-M-0101 at Appendix C 2 (N.Y. PSC 2016) http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7d.

when evaluating certain types of utility expenditures (on distribution projects, distributed energy resources, and energy efficiency programs).[65] While the general method outlined by New York offers a good conceptual example of how state regulators can approach valuing the benefits of resilience, the specific metrics used by utilities appear to better reflect reliability than resilience.[66] New York is not alone; many utilities estimate the value of lost load due to a high-impact, low-probability event using the Interruption Cost Estimate calculator. However, research suggests that this tool, developed primarily for evaluating reliability improvements, is not appropriate to use for evaluating potential resilience improvements.[67] Research is underway to further develop a resilience-focused value of lost load metric.[68]

In the wake of several significant hurricanes, the Public Utility Commission of Texas commissioned a cost-benefit analysis of vegetation management programs, ground-based patrols, infrastructure hardening, and deployment of new technologies.[69] This analysis used a probabilistic hurricane model as well as two primary metrics for evaluating resilience benefits: the avoided cost to repair or replace existing infrastructure, and expected changes in gross domestic product (GDP) for hurricane-prone areas.

Academic researchers are using similar techniques to estimate the resilience value of certain interventions. For example, a group of researchers associated with the National Renewable Energy Laboratory and the City University of New York published a study evaluating the net resilience benefits at the building scale of pairing renewable energy systems with existing backup diesel generators.[70] These existing approaches can serve as a model for regulators and utilities.

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[65] *Id.* at 1-2.

[66] *See, e.g.,* New York State Electric & Gas Corp., BCA Handbook Version 1.1 55-59 (2016), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF0CC59D0-4E2F-4440-8E14-1DC07566BB94%7D.

[67] EPRI at 46.

[68] Anderson, 10 Sustainability 933.

[69] Quanta Tech., Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs 45-66 (2009), http://www.puc.texas.gov/industry/electric/reports/infra/utlity_infrastructure_upgrades_rpt.pdf.

[70] Anderson, 10 Sustainability 933.

Addressing Resilience within the Federal System

The electric grid is an interconnected whole; however, under U.S. law, the grid is subject to divergent and sometimes overlapping regulatory control by federal and state entities. Any needed grid resilience improvements will require action at different levels of government as well as coordination among regulators, grid operators, and utilities. However, that there is bifurcated jurisdictional authority does not imply that there are gaps. Sufficient authorities exist at the federal and state levels to allow for cost-beneficial resilience-enhancing actions, including investments, policies, planning and coordination.

This section begins with a brief overview of the jurisdictional divide in responsibility between state and federal regulators. It then identifies specific regulatory authorities and tools that states have to enhance electric system resilience and makes some recommendations for improvements. Finally, it identifies authorities that the federal government has to enhance electric system resilience and makes recommendations for which authorities are appropriate under different circumstances.

A Brief Overview of the Electric System Jurisdictional Divide

The Federal Power Act gives the states regulatory responsibility over both retail sales of electricity and electric utilities responsible for local distribution infrastructure.[71] In addition, it provides states authority over electric generators (though not over the wholesale sale of the electricity that they produce), including the ability to enact policies that create preferences for certain power sources over others such as renewable portfolio standards. States also have regulatory responsibility over small generators that are interconnected with the distribution system rather than the transmission system, including responsibility for setting the rates paid for electricity generated from these distributed sources.[72]

On the other hand, the Federal Power Act provides the federal government—and FERC, in particular—responsibility to regulate wholesale sales of electricity, interstate transmission of electricity, and the facilities used for that interstate transmission.[73] In two-thirds of the country, federally regulated ISOs/RTOs manage electricity markets that must constantly balance supply and demand under a set of rules approved by FERC.

In addition, in 2005, Congress enacted Section 215 of the Federal Power Act,[74] which gave FERC, in partnership with NERC,[75] the additional responsibility of ensuring the reliable operation of the "bulk power system."

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[71] Federal Power Act (FPA) § 201, 16 U.S.C. § 824 (2015).

[72] Robert R. Nordhaus, *The Hazy "Bright Line": Defining Federal and State Regulation of Today's Electric Grid*, 36 Energy L.J. 203, 207-08 (2015).

[73] FPA § 201(b)(1), 16 U.S.C. § 824(b)(1).

[74] FPA § 215(a)(1), 16 U.S.C. § 824o(a)(1).

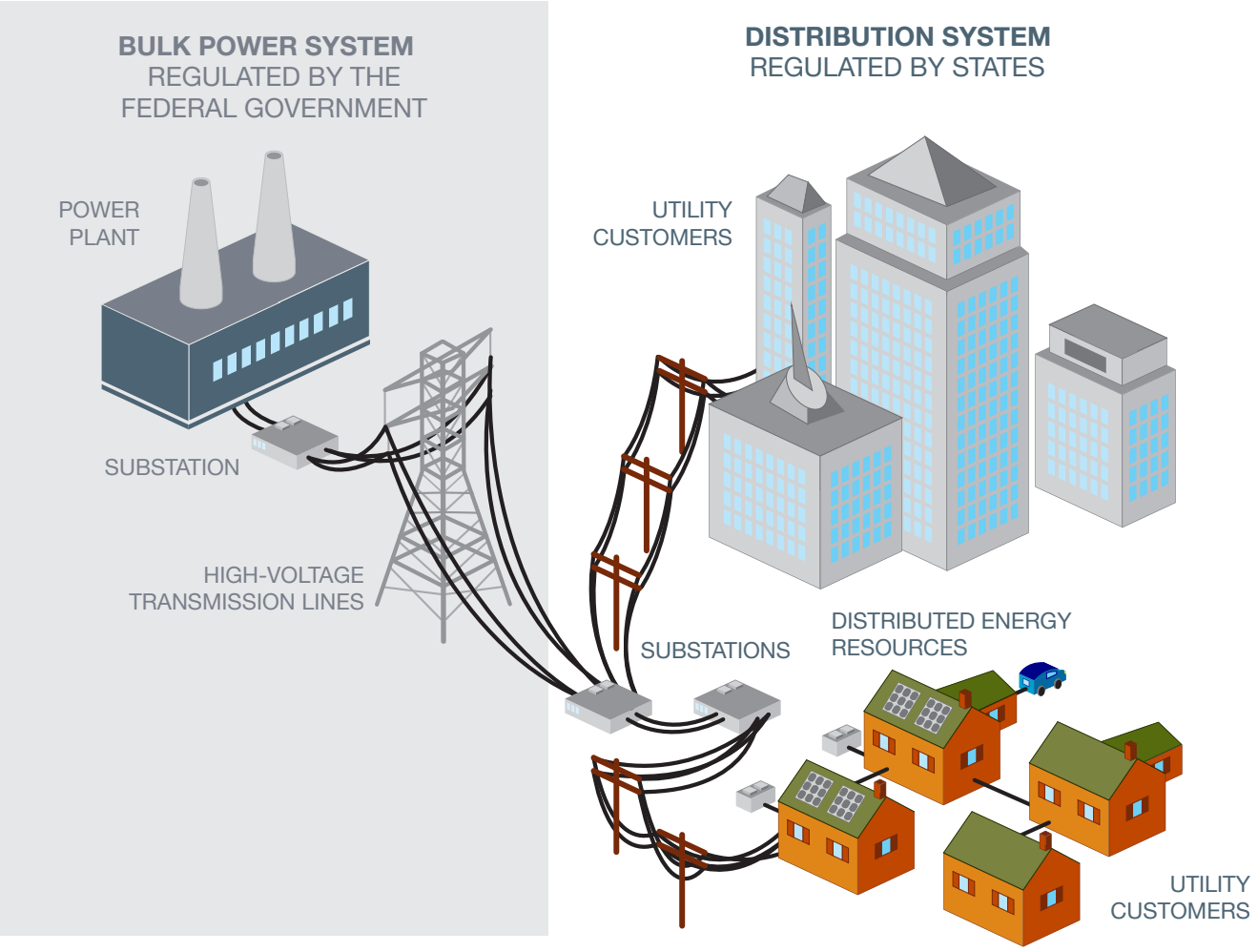
[75] NERC is also responsible for initiating compliance and enforcement actions for mandatory reliability standards, and for *assessing* reliability and resource adequacy, particularly in the face of extreme events. FERC Reliability Primer at 65-71.

Key Term: Bulk Power System

The "bulk power system" includes transmission and related infrastructure and electric generators whose energy is needed to maintain transmission system reliability.[76] The Federal Power Act specifically excludes facilities used in local distribution from the definition of "bulk power system."[77] Figure 8 illustrates the jurisdictional divide between the bulk power system, which is the responsibility of FERC, and the distribution system, which is the responsibility of the states.

Figure 8: Regulatory domains of the electric grid

The electric grid is divided between the bulk power system, subject to FERC and NERC jurisdiction, and the distribution system, subject to state and local regulatory jurisdiction.



[76] FPA § 215(a)(1), 16 U.S.C. § 824o(a)(1).
[77] FPA § 215(a)(1), 16 U.S.C. § 824o(a)(1).

FERC's responsibility under Section 215 of the Federal Power Act is limited to ensuring *operational* reliability—the ability of the system to withstand sudden disturbances without resulting in cascading blackouts.[78] It does not extend to ensuring resource adequacy—the availability of sufficient generating capacity to meet peak electric demand.[79] Under the FERC regulations issued pursuant to Section 215, NERC proposes—either on its own initiative or at the direction of FERC—mandatory reliability standards to be implemented by bulk power system entities such as generators, transmission owners, or regional entities known as "reliability coordinators."[80] FERC will approve a proposed standard so long as it meets statutory and regulatory criteria, including that the standard is a technically sound and efficient means of achieving a reliability goal; was developed initially by industry experts; was based on sound engineering and technical criteria; and is clear and unambiguous regarding its requirements.[81]

Regulation of resource adequacy is, in practice, split between the federal government and states.[82] States have traditionally had authority over resource adequacy. In regions that do not rely on ISOs/RTOs to manage electricity markets, states retain that authority. Over the past 20 years, the federal government has increased its regulatory influence over resource adequacy in some circumstances. A number of ISOs/RTOs have developed "capacity markets"—market-based constructs for meeting resource adequacy needs. The ISO/RTO rules governing these capacity markets fall under FERC's jurisdiction. Other ISO/RTOs have developed resource adequacy constructs that are explicitly designed to reflect shared power between states and federal regulators.[83]

In addition, the Department of Energy retains some authority to coordinate energy-sector information sharing and best practices for critical-infrastructure protection,[84] and to issue certain emergency orders in the face of a grid emergency.[85]

States' Role in Improving Electric System Resilience

Because states have exclusive jurisdiction over distribution-level facilities, which are the source of the vast majority of customer outages from unexpected events,[86] states have focused on grid resilience for some time. States, particularly those that have faced highly disruptive events, have invested significant resources in analyzing opportunities for improving system resilience. We outline three types of opportunities for states to improve electric system resilience.

Directing Distribution Utilities to Make Resilience Investments

The primary way that states can and do improve grid resilience is by directing public utilities under their regulatory authority to invest in key physical and operational systems, and to ensure that utilities can recover the costs of such investments.

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[78] NAS.
[79] FPA § 215(i)(2), 16 U.S.C. § 824o(i)(2).
[80] For many regions the relevant ISO/RTO serves as both grid operator and reliability coordinator.
[81] FERC, Reliability Primer at 55-56.
[82] Nordhaus, 36 Energy L.J. at 210.
[83] *See* Brian R. Gish, *Ensuring Resource Adequacy in Competitive Electricity Markets*, POWER (March 1, 2012), http://www.powermag.com/ensuring-resource-adequacy-in-competitive-electricity-markets/?printmode=1 (describing resource adequacy requirements in the Midcontinent Independent System Operator market).
[84] PPD-21 (detailing DOE authority and responsibilities for energy sector critical infrastructure protection).
[85] FPA § 202(c), 16 U.S.C. § 824a(c); FPA § 215A, 16 U.S.C. § 824o-1.
[86] FERC & NERC, Regional Entity Joint Review of Restoration and Recovery Plans 1 (2016)

Several well-identified interventions that states can undertake to improve resilience include:

- improving vegetation management;[87]
- targeted undergrounding of critical distribution lines;[88]
- load-reduction strategies;[89]
- targeted hardening of distribution lines and substations against storm and physical damage, including through the use of innovative pole and line designs;[90]
- adopting regulation and customer communication plans that facilitate the preparation of selected assets prior to an event to reduce damage in the case of extreme weather events;[91]
- developing strategies for selective restoration and load prioritization to most efficiently restore power and recover from high-impact events;[92] and,
- requiring and overseeing more regular testing of backup power generation equipment at critical facilities.[93]

Additionally, states should consider the extent to which climate change will exacerbate resilience concerns and incorporate climate change directly into resilience-related cost-benefit analyses and risk assessment.[94]

States have indeed adopted many of these strategies as part of their mandate to ensure electric service for customers.[95] Examples include:

- A number of Northeast states require utilities to submit vegetation management plans for Public Utility Commission approval.[96]
- In Washington D.C., the Public Service Commission is responsible for considering a triennial plan filed jointly by the local distribution utility and the District's Department of Transportation for the undergrounding of priority distribution infrastructure.[97]
- Since Hurricane Wilma in 2005, the Florida Public Utility Commission directed distribution utilities to invest in strengthening of distribution lines, pole replacements, and vegetation management. These investments significantly reduced customer outages during Hurricane Irma in 2017.[98]

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[87] EPRI at 35.
[88] *Id.*
[89] *Id.* at 36.
[90] *Id.* at 40.
[91] NAS at 115.
[92] *Id.* at 103.
[93] *Id.* at 96-97.
[94] *See* Justin Gundlach & Romany Webb, Sabin Center for Climate Change Law, Climate Change Impacts on the Bulk Power System: Assessing Vulnerabilities and Planning for Resilience 1-25 (2018), http://columbiaclimatelaw.com/files/2018/02/Gundlach-Webb-2018-02-CC-Bulk-Power-System.pdf.
[95] For an overview of state approaches to resilience, see Edison Elec. Inst., Before and After the Storm: A Compilation of Recent Studies, Programs, and Policies Related to Storm Hardening and Resiliency 1-132 (2014), http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/BeforeandAftertheStorm.pdf.
[96] Lee R. Hansen, State of Connecticut, Utility Tree Trimming in Other States,(2011), http://www.cga.ct.gov/2011/rpt/2011-R-0459.htm.
[97] D.C. Pub. Serv. Comm'n, In the Matter of the Application for Approval of Triennial Underground Infrastructure Improvement Projects Plan (Nov. 12, 2014), https://edocket.dcpsc.org/apis/pdf_files/e8c918a0-d080-4982-83a6-a649d7f64966.pdf.
[98] Alison Silverstein et al., Grid Strategies LLC, A Customer-focused Framework for Electric System Resilience 58 (2018), https://gridprogress.files.wordpress.com/2018/05/customer-focused-resilience-final-050118.pdf.

Rules to Encourage Resilience-Enhancing Distributed Energy Resources

States can also use their distinct role in regulating distributed energy resources (DERs) to enhance grid resilience. DERs, including rooftop solar, electric batteries, backup generators, microturbines, and demand response, can enhance resilience in several ways.[99] Because DERs are generally located close to load, they reduce customers' reliance on vulnerable distribution infrastructure. This is particularly true when DERs can operate as islanded microgrids, allowing them to supply limited power to critical loads during large grid outages of long duration.[100] DERs are nonetheless generally interconnected with the distribution system and so can provide redundant generation supplies in the case of a generation, transmission, or distribution disruption that limits traditional sources' ability to supply energy. Because they are typically much smaller and more geographically dispersed than traditional power plants, DERs can reduce the risk that a single point of generation or transmission system failure will have a significant impact on customers.

Additional interventions related to DERs can improve resilience, including:

- revising utility-DER interconnection agreements to include resilience characteristics such as encouraging the use of enhanced inverters and islanding capability;[101]
- developing customer rate structures that compensate DERs for the quantified resilience value they provide;[102]
- encouragement of islanded microgrids for critical load,[103] including establishing special rates to encourage the development of private microgrids that provide resilience benefitis;[104] and,
- establishing contractual agreements and special rates with DER-owning customers that would permit the utility to use the DERs to supply critical loads during a high-impact event.[105]

Motivated in part by the increased frequency of extreme weather events, many states across the country have recently been ramping up their grid-modernization efforts. While the exact policies differ, many states are looking to advance their resilience goals by increasing the deployment of advanced technology and DERs, such as energy storage and microgrids.[106]

In the aftermath of Superstorm Sandy, New York and New Jersey invested significant resources in DERs and microgrids to reduce outages in the face of future natural disasters. In response to a 2016 report,[107] the New Jersey Board of Public Utilities initiated a process to add microgrids to the state and is currently completing the first step of funding feasibility studies for 13 municipal microgrids.[108]

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[99] Sherry Stout & Eliza Hotchkiss, Nat'l Renewable Energy Lab., Distributed Energy Generation for Climate Resilience (2017), https://www.nrel.gov/docs/fy17osti/68296.pdf. EPRI, Enhancing Distribution Resiliency: Opportunities for Applying Innovative Technologies 11 (2013), https://www.epri.com/#/pages/product/000000000001026889/.

[100] NAS at 106-107.

[101] *Id.* at 107.

[102] *Id.* at 108.

[103] EPRI at 44.

[104] NAS at 107.

[105] *Id.* at 108.

[106] Autumn Proudlove et al., N.C. Clean Energy Tech. Ctr., The 50 States of Grid Modernization: 2017 Review and Q4 2017 Quarterly Report 6 (2018), https://nccleantech.ncsu.edu/wp-content/uploads/Q42017_gridmod_exec_final.pdf.

[107] N.J. Board of Pub. Utils., Microgrid Report (2016), https://www.nj.gov/bpu/newsroom/announcements/pdf/20161130micro.pdf.

[108] N.J. Board of Pub. Utils., Town Center Distrubted Energy Resource Micgrogrid Feasibility Study Incentive Program Application , https://www.nj.gov/bpu/pdf/commercial/TC%20DER%20Microgrid%20Feasibility%20Study%20Application.pdf.

As part of its comprehensive energy strategy known as Reforming the Energy Vision (REV), New York has adopted a series of measures to promote grid resilience through increased deployment of DERs.[109] This includes policies to pay DERs for avoiding needed distribution investments,[110] policies that enable new financing models,[111] and policies that reduce market barriers by facilitating community solar.[112] New York has also implemented policies to expand microgrids. NY Prize is a competition to help local communities develop their own microgrids to "enable the technological, operational, and business models that will help communities reduce costs, promote clean energy, and build reliability and resiliency into the grid."[113]

The Hawaii Public Utility Commission recently approved a Grid Modernization Strategy developed by Hawaii's largest electric utility, Hawaiian Electric Company, at the direction of the Commission.[114] That strategy is intended to "enhance the safety, security, reliability, and resiliency of the electric grid," especially due to the increase in significant weather events.[115] To meet these goals, the plan outlines several steps to facilitate DER integration, such as the deployment of smart meters, enhancement of monitoring technology using SCADA, and use of system inverters to provide greater resilience during voltage deviations.[116] In addition, in January 2018, the Hawaii State Legislature introduced a bill to establish a Homeland Security and Resiliency Council to "assess the resilience of the State's electric grid and other critical infrastructure to natural disasters and other emergencies and make recommendations."[117] In the first sentence of the text of the bill, the legislature references the urgent need for grid resilience in light of Hurricanes Irma and Maria, which struck Puerto Rico in 2017.[118] The goals of the legislation are to prevent the severity of damage to the electric grid from a natural disaster or emergency, enable faster recovery after an outage due to a natural disaster or emergency, and maintain critical loads at critical infrastructure during a natural disaster or emergency.[119] Versions of this legislation have passed both the Hawaii State House and State Senate. As of the time of writing, the two bills are being reconciled.

In 2017, Rhode Island initiated its Power Sector Transformation Initiative, tasking the Public Utilities Commission with reviewing several potential avenues to modernize the grid and designing a new regulatory framework for the state's electric system.[120] The Rhode Island Commission's Phase I report offers seven recommendations with significant resilience implications: microgrid control, fault location and isolation, automated feeder and reconfiguration, remote monitoring, adaptive protection, outage notification, and dynamic event notification.[121]

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[109] *See generally* N.Y. State Energy Planning Bd., 2015 New York State Energy Plan (2015), https://energyplan.ny.gov/Plans/2015.aspx.

[110] N.Y. Dept. of Pub. Serv., Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding, Docket No. 15-E-0751 36-38 (describing demand reduction value and locational system relief value), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b59B620E6-87C4-4C80-8BEC-E15BB6E0545E%7d/

[111] N.Y. State Energy Plan at 32-33.

[112] *Id.* at 27.

[113] *NY Prize*, nyserda.ny.gov, https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize (last visited June 14, 2018).

[114] Haw. Pub. Util. Comm'n, Instituting a Proceeding Related to the Hawaiian Electric Companies' Grid Modernization Strategy, Docket No. 2017-0226 (2018), https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/dkt_2017_0226_2018_02_07_PUC_decision_and_order_35268.pdf

[115] Hawaiian Elec. Cos., Modernizing Hawai'i's Grid For Our Customers 2, 18 (2017), https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/final_august_2017_grid_modernization_strategy.pdf.

[116] *Id.* at 80.

[117] SB2910, 29th Leg., Reg. Sess. (Haw. 2018).

[118] *Id.*

[119] *Id.*

[120] RI Public Utilities Commission, *Power Sector Transformation Initiative*, Nov. 8, 2017, 5:11 PM, http://www.ripuc.org/utilityinfo/electric/PST_home.html.

[121] Div. of Pub. Utils. & Carriers, Office of Energy Res. & Pub. Utils. Comm'n, R.I. Power Sector Transformation 65-66 (2017), http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf.

In March 2017, the Illinois Commerce Commission (ICC) launched NextGrid: an 18-month study to transform the state's grid to be more flexible.[122] NextGrid is designed to be a collaborative process among different working groups comprised of various stakeholders. One working group is dedicated to "Reliability, Resiliency, and Cyber Security" and is tasked with studying solutions to the impacts of feasible risks and attacks both in the present and future.[123]

In 2017, the New Orleans City Council adopted a series of amendments that required utilities to evaluate how the deployment of DERs could increase grid reliability. The objective of the rule change was to "support the resiliency and sustainability of the Utility's systems in New Orleans" and provide the residents of New Orleans with reliable electricity at the lowest cost.[124] To do so, the amendments also require the local utility, Entergy, to determine the appropriateness of implementing new technologies and incorporating renewable energy sources, storage options, and DER.[125]

Local Resilience Rules

Several states have established mandatory standards for enhancing distribution-system reliability. As discussed above, reliability and resilience are distinct concepts, and these reliability standards are generally not designed to address specific resilience concerns. For example, when state regulators establish allowable reliability metrics against which distribution system performance is measured, they often exclude outages caused by major events.[126]

Nonetheless, many states can take advantage of the legal structure and existing institutions tasked with ensuring distribution-level reliability to develop equivalent resilience standards. To the extent that a state identifies a particular resilience vulnerability that can be cost-effectively addressed across utilities, it can consider adoption of a local rule mandating certain performance criteria or operational practices.

Unlike at the federal level, however, there is no single entity tasked with developing distribution-level standards. Institutions that could be responsible for distribution system resilience standards range from Public Service Commissions to customer-owned and publicly owned utilities, and, where they exist, state reliability organizations. For example, the New York State Reliability Council implemented a requirement that natural gas-fired generators interconnected with the ConEd system in New York City must be capable of also burning fuel oil in the case of natural gas supply disruptions.[127] This standard was intended to help address concerns of prolonged outages caused by a disruption in the supply of natural gas.

The Federal Role in Improving Electric-System Resilience

While no part of the Federal Power Act specifically directs any federal agency to improve electric system resilience, existing authorities are, nonetheless, sufficient to address any threats to the bulk power system and to allow the federal

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[122] Ill. Commerce Comm'n, Re Illinois' Consideration of: the Utility of the Future: "NextGrid": Grid Modernization Study (2017), https://nextgrid.illinois.gov/resolution.pdf.

[123] Ill. Commerce Comm'n, *Working Groups*, https://nextgrid.illinois.gov/WorkingGroups.html, (last visited June 14, 2018).

[124] Council of the City of New Orleans, Resolution Amending the Elec. Util. Integrated Res. Plan Rules, R-17-410, at 4 (2017), http://www.all4energy.org/uploads/1/0/5/6/105637723/2017_08_10_ud-17-01_cno_r-17-429_amend_electric_utility_irp_rules.pdf.

[125] *Id.*

[126] NAS at 28.

[127] DOE Staff Report at 91.

government to play an expansive coordinating role. The Federal Power Act places the primary regulatory responsibility over the bulk power system with FERC. Thus, FERC, and the entities it regulates, will have the primary role in evaluating and adopting policies to enhance the resilience of the bulk power system over the long-term. Nonetheless, the Federal Power Act and some other statutory provisions reserve limited authority for other entities, including DOE and NERC.

This section highlights the legal authorities that federal agencies have to ensure the resilience of the bulk power system:

- FERC can use its authority over transmission rates to encourage cost-beneficial investments in the transmission system;
- FERC, in partnership with NERC, can establish reliability standards that have resilience co-benefits;
- Federal agencies can encourage, require, and facilitate better resilience-related coordination and planning by ISOs/RTOs, reliability coordinators, and other entities;
- FERC can work with ISOs/RTOs to evaluate and, if justified, approve wholesale electricity market changes to enhance generation system resilience by compensating generators for well-defined resilience attributes; and,
- DOE and FERC can exercise their authorities to order specific actions in the face of grid emergencies.

Using these authorities to implement every potential intervention that could improve resilience is not feasible; interventions carry costs and other important tradeoffs that must be considered. Thus, when possible, each of these authorities should be exercised only after the relevant agency has determined that the benefits of a proposed action will exceed the costs, using a methodology like that outlined above.

The authorities described in this section are sufficient for the federal government to evaluate and, if necessary, implement cost-beneficial bulk power system resilience improvements and to facilitate resilience-related coordination among federal agencies, regional entities, state regulators, and private utilities.

Is Immediate Federal Resilience Action Needed?

This report focuses on tools that can be used to evaluate potential resilience improvements and the legal authorities that can be used to implement those improvements, when they are needed. There is, of course, a threshold question: are immediate resilience improvements needed?

Many experts that have studied the resilience of the electric system, including the National Academy of Sciences,[128] the Department of Energy,[129] and the Electric Power Research Institute,[130] have identified potential areas for improvement and made recommendations for investments and policy design changes that could be worthwhile. Where they implicate federal authorities, these proposals would be a reasonable place for regulators to start in evaluating cost-beneficial areas for improvement.

However, notwithstanding the potential for cost-effective improvements, it is important to recognize that there is no record supporting concerns about an imminent resilience threat. In rejecting the Department of Energy's proposal to provide cost-of-service payments to certain coal and nuclear plants in the name of grid resilience, FERC recognized that neither the DOE proposal, nor comments supporting the proposal provided a record sufficient to justify a finding that there is a national resilience emergency rendering current electricity markets unjust and unreasonable, let alone one that required substantial out-of-market compensation.[131] This finding was consistent with NERC's 2018 State of Reliability Report, which it released with the headline "*Grid Shows Improved Resilience*, Decreased Protection Systems Misoperations and Advanced Risk Management."[132] FERC did, however, initiate a proceeding to collect more information from ISOs/RTOs to evaluate the state of grid resilience in these wholesale markets.[133] In response to this proceeding ISOs/RTOs submitted information on the state of resilience in wholesale markets, efforts underway to ensure grid resilience, and opportunities for future improvement. These filings make clear that while grid resilience is a critical issue worthy of continued attention, there is no reason to believe any mandatory, national or even regional action to address acute resilience concerns are needed at this time.[134]

FERC Can Establish Transmission-Compensation Rules that Enhance Resilience

FERC's jurisdiction over interstate transmission gives it a role to play in ensuring the resilience of the transmission system. Most outages associated with high-impact, low-probability events occur due to disruptions of the distribution and transmission systems.[135] Investments in the transmission system, if they are cost-beneficial, have the potential to

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[128] *See generally* NAS at 134-140.

[129] *See generally* DOE QER at 7-21 to 7-24.

[130] *See generally*, EPRI at 14-44.

[131] FERC Resilience Order, 162 FERC ¶ 61,012 at P 15.

[132] NERC, Media Release: Grid Shows Improved Resilience, Decreased Protection Systems Misoperations and Advanced Risk Management (June 21, 2018), https://www.nerc.com/news/Headlines%20DL/SOR%202018%20Media%20Release.pdf.

[133] FERC Resilience Order, 162 FERC ¶ 61,012at PP 18-19.

[134] *See, e.g.,* Comments of California Independent System Operator Corp., ISO New England Inc., Midcontinent Independent System Operator, Inc., New York Independent System Operator, Inc., and Southwest Power Pool, Inc., *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 (filed May 8, 2018). One notable exception may be Puerto Rico, where post-Hurricane Maria rebuilding is underway. The Department of Energy recently compiled recommendations for improving the resilience of the island's electric system. U.S. Dep't of Energy, Energy Resilience Solutions for the Puerto Rico Grid (2018), https://www.energy.gov/sites/prod/files/2018/06/f53/DOE%20Report_Energy%20Resilience%20Solutions%20for%20the%20PR%20Grid%20Final%20June%202018.pdf. The analytical tools and authorities outlined in this report could be useful as Puerto Rico works to rebuild its electric system.

[135] *See* Trevor Houser, John Larsen & Peter Marsters, The Rhodium Group, *The Real Electricity Reliability Crisis* (Oct. 3, 2017), https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr/ [hereinafter Rhodium Group Outage Analysis] (showing that only 0.00858% and 0.000007% of major electricity disturbances were caused by generation inadequacy and fuel supply emergencies during 2012-2016).

enhance each phase of grid resilience, including its ability to absorb and resist shocks, manage disruptions as they occur, quickly recover, and respond and adapt to future shocks.[136]

FERC has authority over the rates and tariffs of transmission providers and can use this authority to ensure that transmission developers will be compensated for providing services that enhance the resilience of the transmission system. For example, FERC has already issued an order that requires utilities to have spare transformers, which provide significant system-restoration benefits while reducing the cost needed for all utilities to maintain spare transformers.[137] The National Academy of Sciences has identified mechanisms by which FERC can use its existing transmission authority to cost-effectively expand the availability of spare transformers through a national transformer reserve.[138]

In addition, FERC can use its transmission ratemaking authority to encourage, either directly or through ISOs/RTOs, cost-beneficial investments that will enhance transmission-system resilience, including hardening of vulnerable assets against extreme weather such as flooding or earthquakes; burying of key transmission lines; shielding of critical transmission equipment against electromagnetic attack; and more regular and innovative vegetation management.[139]

FERC Can Approve Reliability Standards that Have Resilience Co-benefits

FERC can use its existing authority to implement mandatory operational, planning, and performance requirements that improve grid resilience when doing so is a co-benefit of actions that enhance reliability. FERC's existing reliability standards have mandated planning, coordination, and investments that have generally supported a resilient electric system.

Under Section 215 of the Federal Power Act, FERC and NERC are responsible for issuing reliability standards—enforceable requirements intended to ensure the operational reliability of the bulk power system. While reliability and resilience are different concepts,[140] protecting against reliability risks can often have significant resilience co-benefits.

Many of the reliability standards that have been proposed by NERC and approved by FERC establish planning, analytical, or operational requirements that also improve the resilience of the bulk power system at each of the phases, including by (1) avoiding and resisting damage to the electric grid during a high-impact, low-probability event, (2) enhancing coordination during the event to manage damage that does occur, (3) speeding up the recovery of the system after such an event, and (4) analyzing past events to identify areas for future recovery and adaptation. For example, the following reliability standards have significant resilience co-benefits:

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[136] Hardening key weak points on the transmission system can increase the system's ability to absorb and resist shocks. New software and hardware systems are in development that, if deployed, may be able to help grid operators manage disruptions as they occur by rerouting electricity around overloaded elements. *See* Pablo A. Ruiz et. al, Transmission Topology Optimization, *Increasing Market and Planning Efficiency and Enhancing Resilience through Improved Software*, Docket No. AD10-12-0009 (June 26, 2018) Ensuring availability of non-wires transmission assets such as transformers can reduce the time needed to replace damaged equipment. And new tools are being developed to help transmission planners target investments by identifying "weak" points on the system that can cause cascading failures, Yang Yang, Takashi Nishikawa & Adilson E. Motter, *Small vulnerable sets determine large network cascades in power grids*, 358 Science 6365 (2017), http://science.sciencemag.org/content/358/6365/eaan3184.

[137] *Order on Application for Blanket Authorization for Transfers of Jurisdictional Facilities and Petition for Declaratory Order*, 116 FERC ¶ 61,280 (2006).

[138] NAS at 117-19.

[139] EPRI at 25-34.

[140] Policy Integrity Comments on DOE NOPR at 11-12.

- CIP-014-2 (Physical Security), requiring identification of critical transmission substations and performance of physical security risk assessments;
- CIP-009-6 (Cyber Security – Recovery Plans for BES Cyber Systems), requiring development and implementation of recovery plans in the event of cybersecurity threats;
- TPL-001-4 (Transmission System Planning Performance Requirements), requiring assessment of the impacts of "extreme events" on the bulk power system and planning for "N-2" extreme events;
- FAC-008-3 (Facility Ratings), requiring ratings for how well facilities operate in emergency situations; and,
- EOP-010-1 (Geomagnetic Disturbance Operations) and TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events), requiring planning and emergency operation procedures in the event of a geomagnetic disturbance.

To the extent that analyses from the Commission, ISOs/RTOs, or NERC identify gaps that are not appropriately filled by mandatory standards, improvements to existing reliability standards or promulgation of new standards may enhance both reliability and resilience. For example, in 2016 and 2017, FERC and NERC conducted an extensive study of transmission-operator and reliability-coordinator system restoration plans and issued two reports outlining a host of improvements that could further enhance bulk power system recovery from sustained widespread outages.[141] Recently, FERC adopted an order directing NERC to develop a reliability standard that requires mandatory reporting of cybersecurity incidents, which is intended to improve resilience by giving regulators, grid operators, and utilities the information they need to learn and adapt.[142]

One benefit of improving resilience using FERC's reliability standard authority is that it covers a wider range of entities compared to FERC's jurisdiction over wholesale energy and transmission. For example, reliability standards apply to federal power agencies, municipal utilities, rural electric cooperatives, and Texas, which are all largely exempt from FERC's ratemaking jurisdiction.[143] Under its reliability standard authority, FERC can direct NERC to evaluate opportunities to expand existing reliability standards or propose new standards that improve operational reliability, with the co-benefit of improved system resilience. For example, FERC could evaluate the benefits and costs of adopting the currently voluntary NERC reliability guideline aimed at improving generation system resilience, the Reliability Guideline for Generating Unit Winter Weather Readiness, as a mandatory reliability standard.[144] This guideline outlines best practices for the development and implementation of plant-specific winter readiness plans. These plans provide plant owners the tools needed to anticipate, prevent, respond to, and recover from equipment outages caused by extreme cold. On the other hand, investigation may show that existing practices and standards are meeting resilience needs.[145]

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[141] FERC & NERC, Regional Entity Joint Review of Restoration and Recovery Plans 1 (2016), https://www.ferc.gov/legal/staff-reports/2016/01-29-16-FERC-NERC-Report.pdf [FERC & NERC Joint Review]; FERC, Further Joint Study Report: Planning Restoration Absent SCADA or EMS (PRASE) (2017), https://www.ferc.gov/legal/staff-reports/2017/06-09-17-FERC-NERC-Report.pdf. [FERC & NERC Further Joint Review]

[142] *Cyber Security Incident Reporting Reliability Standards*, Order No. 848, 164 FERC ¶ 61,033 (2018).

[143] FERC Reliability Primer at 6.

[144] NERC, "Reliability Guideline: Generating Unit Winter Weather Readiness—Current Industry Practices," August 2013, http://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/Relibility_Guideline_Generating_Unit_Winter_Weather_Readiness.pdf.

[145] Staffs of FERC and NERC and its Regional Entities, Recommended Study: Blackstart Resources Availability (2018), https://www.ferc.gov/legal/staff-reports/2018/bsr-report.pdf.

Federal Agencies Can Mandate or Facilitate Planning and Coordination Among Regional Entities

Given the fractured nature of regulatory and planning responsibilities across the federal system, a key opportunity for improving system resilience is increased coordination and planning. In filings as part of FERC's resilience docket, a number of ISOs/RTOs rightly identified planning and coordination as providing important resilience benefits and identified potential improvements.[146] The federal government is well positioned to lead this effort. Enhancing coordination and planning can improve all phases of grid resilience, including by identifying opportunities to avoid or resist damage, enhancing communication so that all responsible actors can manage disruption during a shock, coordinating deployment of resources to quickly responding to a shock after it occurs, and identifying lessons learned and investments needed to recover from and adapt to future shocks.

Transmission Planning and Coordination. FERC has designated regional organizations to be responsible for mandatory transmission planning. While transmission planning has long been a responsibility of ISOs/RTOs, FERC expanded transmission planning to regions without ISOs/RTOs in its Orders No. 890 and 1000.[147] Regional transmission planners are required to work with member transmission and generation owners to complete an Annual Transmission Planning Assessment.[148] This assessment requires planners to evaluate the transmission system against a wide range of contingencies, many of which have resilience implications. These assessments can be used to direct transmission investments using new tools that facilitate targeting high-value investments, such as a model developed for identifying "weak" points on the transmission system that can cause cascading failures.[149] Coordination of transmission planning can also help facilitate transmission-system resilience. Planning must already be coordinated with "appropriate state authorities."[150] FERC can also encourage or require regional transmission planners to coordinate planning across regions.

Reliability Planning and Coordination. NERC has delegated certain authority over bulk power system reliability to regional reliability coordinators.[151] Reliability coordinators already perform important planning and coordination functions that can be leveraged to analyze and recommend resilience improvements. For example, transmission operators are required to have reliability coordinator-approved plans for system restoration following a widespread outage or

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[146] Comments of Southwest Power Pool, Inc. on Grid Resilience Issues, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 at 8-9 (filed March 9, 2018) [hereafter "SPP Resilience Response"] (discussing SPP's role in general system and contingency planning, including scenario planning that covers high-impact low-probability risks); PJM Resilience Response at 49-50 (identifying a number of ways to think about resilience in the transmission planning process); *id.* at 63-64 (operations plans including load shedding plans help ensure that outages are minimized when they do occur before recovery can begin); Responses of the Midcontinent Independent System Operator, Inc., *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 at 3-4 (filed March 9, 2018) at 3-4 (discussing importance of transmission planning to identify needed expansions in light of grid resilience).

[147] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 435 (2007); *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011).

[148] NERC Reliability Standard TPL-001-04 – Transmission System Planning Performance Requirement, Eff. Jan. 1, 2015; *See* SPP Resilience Response (describing use of Annual Planning Assessment to address resilience concerns).

[149] Yang Yang et al., *Small Vulnerable Sets Determine Large Network Cascades in Power Grids*, 358 Science 6365 (2017), http://science.sciencemag.org/content/358/6365/eaan3184.

[150] 18 CFR § 35.34(k)(7).

[151] FERC Reliability Primer at 27. Generally ISOs/RTOs serve as the reliability coordinator for their region. *See* http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx. Note that CAISO does not currently act as its own reliability coordinator.

blackout.[152] Similarly, reliability coordinators are required to have area restoration plans.[153] Where improvements to other resilience phases (limiting initial damage, continued operation during an event) can be justified as improving reliability, FERC and NERC can use their reliability authority to require similar coordination and planning applicable to those phases. FERC and NERC can then conduct a comprehensive assessment of relevant plans to identify weaknesses and make cost-beneficial recommendations for improvement, as they recently did in a series of reports assessing existing restoration and recovery plans.[154]

Other Planning and Coordination. The Department of Energy has been designated as the Sector Specific Agency for the energy sector pursuant to Presidential Policy Directive 21.[155] Under this directive, DOE plays an important coordinating role. It is responsible for day-to-day prioritization and coordination of energy-sector critical infrastructure protection activities; carrying out incident management responsibilities; providing support and facilitating technical assistance and consultations with the energy industry; and coordinating with the Department of Homeland Security, other agencies, and the energy sector to implement the directive.[156] In addition, the National Academy of Sciences has outlined several recommendations for DOE, FERC, NERC, and regional entities such as ISOs/RTOs to improve general system planning and coordination with the goal of enhancing resilience. Potential actions include expanding emergency preparedness exercises,[157] information sharing to disseminate resilience best practices,[158] and coordinating natural gas and electric sectors to reduce fuel disruption risks.[159]

FERC Can Approve Market Rules that Create Incentives for Generation-System Resilience

FERC can use its authority over wholesale electricity market rules to evaluate and, if they are just and reasonable, approve proposals from grid operators that align generator incentives with resilience-enhancing entry, exit, and operational behavior. Market-based solutions may be an appropriate tool where services that enhance generation system resilience can be identified and defined with specificity, and where analysis shows that procurement of these services will enhance electric *system* resilience to an extent sufficient to justify the costs. As PJM Interconnection, the grid operator for states in the Midwest and Mid-Atlantic, stated in a filing to FERC regarding resilience improvements in wholesale markets, such solutions, when available, are preferable to alternatives where customers are responsible for cost-based payment to certain identified resources: "assuming that resilience requirements can be clearly articulated, meeting them through market-based solutions that allow resources to compete to meet those requirements is the preferred way to ensure that these objectives are met at the lowest cost to consumers."[160] However, there are limited circumstances where new market rule changes for generators will provide substantial electric system resilience enhancements. Therefore, FERC should

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[152] NERC Reliability Standard EOP-005-2 - System Restoration from Blackstart Resources, Eff. May 23, 2011, http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-005-2.pdf.

[153] NERC Reliability Standard EOP-006-2 - System Restoration Coordination, Eff. May 23, 2011, http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-006-2.pdf.

[154] FERC Joint Review; FERC Further Joint Review.

[155] PPD-21.

[156] *Id.* Notably, however, this directive does not provide with DOE with any additionally regulatory authority.

[157] NAS at 134.

[158] *Id.* at 135.

[159] *Id.* at 135.

[160] Comments and Responses of PJM Interconnection L.L.C. at 68, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 (filed March 9, 2018).

ensure that proposals justified on the basis of resilience are supported by substantial evidence that they will result in measurable enhancements to electric system resilience.[161]

FERC has authority to approve and require such market-based solutions. FERC has jurisdiction over rules and practices affecting wholesale electricity rates,[162] and is responsible for ensuring that those rates are "just and reasonable."[163] Courts have interpreted the Federal Power Act to provide FERC the authority to approve and police a wide variety of ISO/RTO market rules. These rules can ensure just and reasonable wholesale rates by creating incentives for market participants to provide efficient levels of desired generator attributes.[164] And because generation system outages, in the limited circumstances that they occur, impose substantial costs on market participants, market changes aimed at reducing the likelihood and consequence of outages caused by high-impact, low-probability events fits squarely within FERC's authority.

That FERC has authority to approve market changes to enhance resilience does not necessarily mean that additional rules are required. A number of market-based constructs and enhancements have already been implemented to facilitate procurement of generator or electric-system services that enhance the resilience of the generation system.

- **Ancillary Services Markets.** NERC has catalogued the "essential reliability services" needed to ensure operational reliability.[165] Some of these services are provided through market mechanisms—called "ancillary services markets." For example, in some ISOs/RTOs, existing market rules provide for compensation of ancillary services that affect reliability and resilience, such as contingency reserves[166] and black-start.[167]
- **Capacity Markets.** A number of ISOs/RTOs manage capacity markets, market-based constructs intended to meet resource adequacy requirements. While resource adequacy is primarily a reliability attribute, reserve margins can help the system avoid and manage system disruption by lessening the risk that disruption of certain generation assets by high-impact, low-probability events will result in long lasting, widespread outages.

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[161] Because resilience currently has high salience, there is some risk that advocates attempt to justify preexisting policy proposals using grid resilience even if they are not directly aimed at improving resilience. For example. in its response to FERC's information request on grid resilience, PJM advocated for certain energy market pricing reforms. *Id.* at 78-80. But these price formation reforms, whatever their merits, "do not include even an attempted nexus to bulk power system resilience." FERC Resilience Order, 162 FERC ¶ 61,012 at P 16 & n. 25.

[162] FPA § 205(a), 16 U.S.C. § 824d(a).

[163] *Id.*

[164] *Advanced Energy Mgmt. All. v. FERC*, 860 F. 3d 656 (D.C. Cir. 2017); *Connecticut Dept. of Pub. Util. v. FERC*, 569 F.3d 477 (D.C. Cir. 2009). *FERC v. Elec. Power Supply Assoc'n*, 136 S. Ct. 760 (2016).

[165] NERC, Essential Reliability Standards Working Group, Essential Reliability Services Working Group Sufficiency Guideline Report (2016), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf.

[166] EPRI, Wholesale Electricity Market Design Initiatives in the United States: Survey and Research Needs at 3-46 to 3-49 (2016), https://www.epri.com/#/pages/product/000000003002009273/ [hereafter "EPRI Market Design"]. Contingency reserves are reserves that may be needed in the case of unplanned outages of significant generation or transmission facilities.

[167] *See* Nitish Saraf et al., The Annual Black Start Service Selection Analysis of ERCOT Grid, 24 IEEE Transactions on Power Systems 1867 (2009). Black-start is the ability to supply initial power to generators so that they can be brought back online and is an important resilience attribute that is critical for system restoration. EPRI at 30. Note, however, that not all ISOs/RTOs procure black-start service through a competitive mechanism. For example, CAISO compensates black-start resources on a cost-of-service basis. *California Independent System Operator*, 161 FERC ¶ 61,116 (2017). Cost-based provision of resilience attributes may be appropriate when market-based solutions are not feasible; however, consistent with FERC's approach to reliability, the use of such mechanisms should be limited and, when possible, time-limited. *PJM Interconnection, LLC*, 110 FERC ¶ 61,053 at P 114 (2005) ("a transparent market process is preferable to cost-of-service rates that can cause high uplift payments . . . . [O]ur policy on reliability compensation will be to rely on markets and proper market design, and to use non-market solutions only as a last resort"); *New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61116 at P 16(2015) ("RMR filings should be made only to temporarily address the need to retain certain generation *until more permanent solutions are in place*") (emphasis added).

- **Generator Performance.** Partially in response to FERC action taken in the aftermath of the Polar Vortex,[168] PJM and ISO New England have implemented market reforms to charge generators that are unable to meet their capacity obligations a penalty and make additional payments to those that can.[169] These initiatives can provide efficient incentives for generators to change their behavior in ways that avoid or reduce the consequence of expected outages caused by high-impact, low-probability events. For example, generators would be incentivized to invest in weatherization to protect against extreme weather events or to sign firm fuel contracts to protect against natural gas supply disruptions.

- **Removal of Market Participation Barriers.** FERC has adopted rules that require grid operators to provide for the participation of new technologies—such as demand response and energy storage—in existing energy, capacity, and ancillary services markets.[170] These market enhancements broaden the scope of resources that are able to provide the resilience-enhancing services beyond traditional generation resources.

It is conceivable that there are additional, measurable services that resources with particular attributes can provide that can be shown to increase resilience, or resource types that are excluded from providing existing services, To the extent that such services and resources are identified, changes to market rules could be appropriate if supported by analysis that the expected benefits of such changes justify the costs.

However, any use of these options is limited in important ways. First, electricity markets primarily affect the entry, exit, and operation incentives for generation resources. Only a very small proportion of electric-system outages are caused by failures of the *generation* system.[171] And additional generation is primarily useful for *resisting* and *avoiding* outages caused by insufficient generation, with limited utility for managing, recovering from, or adapting to high-impact, low-probability shocks. Therefore, even policies that enhance the resilience of the generation system provide limited opportunities to enhance *electric-system* resilience.

Second, market rules are best suited for facilitating the efficient procurement of specific generation resource attributes. As such, changing market rules to incentivize resilience is only appropriate where attributes have been shown to have a direct connection to resilience improvements—that is, that the attributes allow generators to provide services or products that will help the electric system withstand, respond to, or recover from a high-impact, low-probability shock. And to the extent that substantial evidence can demonstrate the connection between particular generator attributes, and resilience-enhancing capabilities, those attributes have to be defined with sufficient specificity to allow price formation. To-date, resilience-specific attributes (as distinguished from those that also facilitate provision of reliability services) have not been identified and defined. Market regulators, therefore, must be careful to ensure that the attributes identified actually support resilience. There is no evidence that many of the generator attributes highlighted as part of recent political discussions actually provide resilience benefits.

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[168] *Order on Technical Conferences,* 149 FERC ¶ 61,145 (Nov. 20, 2014).

[169] DOE Staff Report at 91-92. PJM instituted its Capacity Performance Proposal, which was approved by the Commission. *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 ("Capacity Performance Order"), *order on reh'g and compliance,* 155 FERC ¶ 61,157 (2015). The New York ISO identified, adopted, and implemented its Comprehensive Shortage Pricing enhancements. *New York Independent System Operator Inc.*, 154 FERC ¶ 61,152 (March 1, 2016). ISO New England identified its Pay For Performance capacity market design, to be implemented in 2018. Fuel Assurance Status Report of ISO New England Inc. at 5-9, Docket No. AD14-8-000 (Feb. 18, 2015).

[170] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018) (providing for participation of energy storage); *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008) (providing for participation of demand response in ancillary services and capacity markets).

[171] *See* Rhodium Group Outage Analysis; Silverstein at 18-20.

Third, market rules designed to compensate for individual attributes may improve resilience against certain threats but exacerbate resilience against other threats. For example, a resilience proposal aimed at compensating "fuel security"[172] might, in practice, reward large central-station powerplants that have on-site access to fuel. Yet such resources often pose countervailing resilience concerns because unexpected outages of these resources place more strain on the electric system and they are often less resistant to extreme weather conditions. To the extent additional fuel-security payments increase reliance on such generators or slow the replacement of these resources with newer technologies, such payments may ultimately harm resilience on net. Use of narrow definitions of resilience attributes such as "fuel security" also risks under-compensating and, therefore, under-providing, the resilience improvements of generation resources *without* fuel requirements.

Therefore, it is not sufficient for policymakers merely to identify individual attributes that are nominally related to resilience as sufficient justification for market changes. Rather, FERC and ISOs/RTOs should first conduct holistic analyses that evaluate how any contemplated market changes would likely affect *system* resilience against multiple threats, in comparison to the impact of other potential changes.

Moreover, while cost-benefit analysis is an important tool to evaluate any resilience intervention, it is particularly important for market-based solutions. Market changes, if not done well, can impose substantial costs on consumers by distorting efficient entry, exit, and operational decisions. The potential that market changes will result in very large costs and low or ill-defined benefits suggests that a thorough cost benefit analysis should be required in order for FERC to make any determination that market changes intended to enhance resilience are "just and reasonable."

DOE Can Issue Emergency Orders to Address Rare and Unforeseen Events If They Occur

Notwithstanding all responsible planning, coordination, and investment, high-impact, low-probability events can cause significant outages and damage. Grid operators can implement the contingency plans they have developed to facilitate the speedy recovery from such outages. However, in the unexpected and rare case that existing plans and tariffs are insufficient to address recovery needs after a high-impact, low-probability event, federal regulators—specifically DOE and FERC—have been delegated emergency authorities by Congress that can be used under limited circumstances. While these authorities are broad, they come with important limits.

First, under long-standing authority codified in Section 202(c) of the Federal Power Act, DOE can issue emergency orders requiring the interconnection of electric facilities and the generation, transmission, and delivery of electricity.[173] These orders can be issued on DOE's own or after an application by the owner of generation, transmission, or distribution facilities affected by an emergency.[174] DOE can use this authority to enable grid operators to deviate from operations under existing market rules to facilitate recovery and restoration in the event of an emergency. Section 202(c) establishes the limits under which DOE may act. DOE's emergency authority is intended to address relatively short-term and unexpected events, not long-term changes to the electric system. Long-term changes should be handled in the

[172] *See, e.g.*, PJM, Valuing Fuel Security (2018), http://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180430-valuing-fuel-security.ashx [hereinafter "PJM Fuel Security Proposal"].
[173] 16 U.S.C. § 824a(c).
[174] 10 C.F.R. § 205.370.

normal course.[175] Moreover, DOE's authority is not intended to address economic concerns of specific generators. The Federal Power Act and DOE's regulations encourage power-sector entities to use existing rates or negotiate mutually acceptable rates with other power-sector entities.[176] But Congress provided FERC, not DOE, the ultimate authority to determine "just and reasonable" compensation for compliance with emergency orders, "in accordance with its standard procedures."[177]

Second, in 2015, Congress delegated to DOE additional authority under Section 215A of the Federal Power Act to impose mandatory security measures to restore critical infrastructure in the case of grid-security emergencies.[178] Grid-security emergencies are limited to cyberattacks, electromagnetic pulse attacks, geomagnetic storms, and direct physical attacks that *have occurred* or pose an *imminent* danger.[179] Under this provision, after the President of the United States has declared a grid-security emergency, DOE can issue emergency orders to utilities, NERC, and regional entities to implement emergency security measures. Like with Section 202(c), this authority is not intended to address economic concerns of generators and authority to set "just and reasonable" compensation is delegated to FERC.[180]

These authorities provide needed flexibility so that relevant generators, utilities, grid operators, and regulators can respond to the particular circumstances caused by a disruptive event. But the emergency powers are appropriately circumscribed by Congress and the courts. Congress authorized DOE and FERC to use these authorities only under specific conditions during and immediately after an incident. Section 202(c) provides DOE authority to issue emergency orders only "*during* the continuance of any war" and "whenever the Commission determines that an emergency *exists*."[181] DOE may only order the "*temporary* connections of facilities" and the "generation, delivery, interchange, or transmission that will *meet* the emergency."[182] And DOE's authority to allow facilities to avoid environmental requirements is limited to a (renewable) 90-day period.[183] Section 215A sets strict time limits on DOE's authority. DOE may only issue emergency orders for periods of 15 days, and may only renew orders if the Secretary of Energy certifies that the emergency continues to exist or the measures continue to be required.[184] That is, these emergency authorities are aimed at the *manage* and *quickly respond* phases of grid resilience, rather than the *resist/avoid* and *recover/adapt* phases.

In addition, any DOE or FERC action is subject to judicial review.[185] This allows courts to exercise oversight in order to ensure that any emergency order issued by DOE has been justified through sufficient record evidence and limits DOE's ability to implement far-reaching emergency orders that are inconsistent with Congress's intent that they be used in limited circumstances.

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[175] *See* FPA § 202(c), 16 U.S.C. § 824a(c) ("defining "emergency" as ""a *sudden* increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy"); 10 C.F.R. § 205.371 (defining emergency using terms such as "sudden" "unexpected" or "unforeseen"); 10 C.F.R. § 205.375 (outlining factors to be considered when evaluating an energy supply shortage); *see also Richmond Power & Light v FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) ("That section speaks of "temporary" emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor").

[176] FPA § 202(c)(1), 16 U.S.C. § 824a(c)(1) ("If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order . . . . "); 10 C.F.R. § 205.376.

[177] 10 C.F.R. § 205.376; FPA § 202(c), 16 U.S.C. § 824a(c)(1).

[178] *See* FPA § 215A, 16 U.S.C. § 824o-1.

[179] FPA § 215A(a)(7), 16 U.S.C. § 824o-1(a)(7).

[180] FPA § 215A(a)(6), 16 U.S.C. § 824o-1(a)(6).

[181] FPA § 202(c)(1), 16 U.S.c. § 824a(c)(1) (emphasis added).

[182] *Id.* (emphasis added).

[183] FPA § 202(c)(4)(A), 16 U.S.c. § 824a(c)(4)(A).

[184] FPA § 215A(a)(5), 16 U.S.C. § 824o-1(a)(5).

[185] FPA § 313(b), 16 U.S.C. § 825l(b).

Key Takeaways for Proposals to Subsidize Coal and Nuclear Plants Based on Grid Resilience

The Trump Administration has used the concept of grid resilience to argue for policies to provide out-of-market financial support to existing coal and nuclear generators. First, in September 2017, DOE issued a Notice of Proposed Rulemaking ("DOE NOPR") requesting that FERC approve changes to ISO/RTO markets in the name of grid resilience.[186] The DOE NOPR, if adopted, would have guaranteed cost-based compensation to coal and nuclear plants that maintained substantial on-site fuel supplies, thereby shielding those units from competitive market forces. DOE justified this proposal on the grounds that retirement of these units would risk undermining electric system resilience and therefore result in unjust or unreasonable wholesale rates. FERC ultimately rejected the proposed rule, determining that DOE had not provided a sufficient record to support its proposal.[187]

More recently, President Trump issued a directive to DOE to limit the closure of coal and nuclear plants.[188] The Administration is contemplating action under Section 202(c) of the Federal Power Act and under provisions of the Defense Production Act of 1950. Under these authorities, the federal government would mandate that distribution utilities and grid operators purchase electricity from certain coal and nuclear generators. The Trump Administration has asserted that these emergency actions are needed to maintain national security; however, the underlying national security argument for coal and nuclear bailouts generally overlaps with the resilience concerns that motivated the DOE NOPR. Specifically, a leaked memo explains the Administration's concern that, without "fuel-secure" generation such as coal and nuclear, a high-impact, low-probability shock risks disrupting the electric system and leaving critical defense facilities without power. While the contours of a proposal have been reported in the press, no official action has been taken and DOE has not provided a timeline for when it will act in accordance with President Trump's directive.

The insights provided in this report can be useful in evaluating these policy proposals.

Urgent and Unprecedented Action Is Not Necessary or Appropriate Because There Is No Grid Resilience Emergency

With proper analysis and deliberate policymaking, regulators can identify investments or policies that would cost-effectively improve grid resilience. However, as is discussed in this report, the expert judgment of the entities responsible for the continued operation of the bulk power system—FERC, NERC, and the ISOs/RTOs—makes clear that there is not presently a national grid resilience emergency. To the extent that further analyses determine cost-beneficial resilience improvements, the existing authorities described above are available to craft the appropriate transmission investment, minimum standard, planning/coordination, or market-based compensation solution. The use of untested, ill-fitting "emergency" authorities—such as authority under the Defense Production Act designed to ensure that the federal

[186] DOE NOPR at 46,945.
[187] FERC Resilience Order, 162 FERC ¶ 61,012 at P 15.
[188] Brad Plumer, *Trump Orders a Lifeline for Struggling Coal and Nuclear Plants*, N.Y. Times (June 1, 2018), https://www.nytimes.com/2018/06/01/climate/trump-coal-nuclear-power.html.

government has priority in the purchase of needed materials and products—is, therefore, not necessary or appropriate to make national security-related grid resilience improvements.[189]

Policy Focused Narrowly on Certain Threats Obscures Resilience Consequences of Other Threats

The Trump Administration has asserted that it is responding to fuel supply and other disruptions caused by cyber and physical attack.[190] As explained above, adopting policy based on a limited threat assessment risks exposing the electric system to other threats. Even if coal and nuclear units were less exposed to *pipeline* cyberattack , they may be more or equally exposed to a direct cyberattack or an attack on transmission infrastructure.[191] Recent forced outage rates during extreme weather suggest that deepening dependence on older resources may also reduce resilience to those threats.[192] A holistic assessment of reasonable threats and analysis of the type describe in this report would be necessarily to determine whether the contemplated policy will enhance or detract from generation system resilience.

Proposals to Support "Fuel Secure" Generation Demonstrate Why Attribute-Based Resilience Metrics can be Misleading and Unhelpful

Both proposals would support resources because they possess "fuel security" attributes (defined in the DOE NOPR to mean on-site fuel storage, and in recent proposals to mean generation that is not dependent on natural gas pipelines). As explained above, attribute-based resilience metrics are less useful in evaluating resilience improvements than performance-based metrics. Thus, special care must be taken to ensure that if policy is designed to compensate for certain generator attributes, those attributes, in fact, enhance system resilience. Yet, there are no well-established studies that, relying on realistic assumptions, show that increasing the availability of generators with "fuel security" attributes will enhance the resilience of the electric system. Incentivizing plants with on-site fuel storage may reduce some risks of generation outages due to fuel supply disruption, but may increase other fuel disruption risks, including risk to the fuel stored on-site.[193] And by prejudging the importance of a single, narrow attribute, policymakers may miss alternatives such as hardening fuel transportation infrastructure or installing fuel-free resources that more cost-effectively or comprehensively enhance generation system resilience.

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[189] *See* 50 U.S.C. § 4511(a)(1) (permitting use of priority contracting and allocation authority only for actions "necessary or appropriate to promote the national defense"); *see also* Joint Trade Association Letter to Secretary Rick Perry Regarding Emergency Authorities at 6-10 (May 7, 2018), https://info.aee.net/hubfs/Trade_Letter_Legal%20Analysis_DOE_5-7-18.pdf.

[190] *See* Jennifer A Dlouhy, *Trump Prepares Lifeline for Money-Losing Coal Plants*, Bloomberg (June 1, 2018), https://www.bloomberg.com/news/articles/2018-06-01/trump-said-to-grant-lifeline-to-money-losing-coal-power-plants-jhv94ghl (citing a leaked DOE memo that describes cyber and physical threats to the electric and gas systems).

[191] *See* Rebecca Smith, *Russian Hackers Reach U.S. Utility Control Rooms, Homeland Security Officials Say*, Wall Street Journal (July 23, 2018), https://www.wsj.com/articles/russian-hackers-reach-u-s-utility-control-rooms-homeland-security-officials-say-1532388110 (describing compromised electric utility systems that could result in outages of transmission and generation systems).

[192] *See* Ariel Horowitz et al, Synapse Energy Economics, Comments on the United States Department of Energy's Proposed Grid Resiliency Pricing Rule at E-22 to E-25 (2017), http://www.synapse-energy.com/sites/default/files/Grid-Resiliency-Whitepaper-As-Filed-17-085.pdf.

[193] Mark Watson, *Harvey's Rain Caused Coal-to-Gas Switching: NRG Energy*, S&P Global Platts (Sept. 27, 2017), https://www.platts.com/latest-news/electric-power/houston/harveys-rain-caused-coal-to-gas-switching-nrg-21081527.

Additional Generator Attributes that Are Bad Resilience Metrics

In order to justify support for nuclear and coal plants, the Trump Administration has primarily pointed to narrow definitions of "fuel security" as the relevant resilience attribute. However, DOE has pointed to other generator attributes that are not good metrics for resilience as support for its proposals. These include:

The number of plants operating as baseload resources.[194] The term "baseload" refers to the minimum level of demand on an electrical grid over a span of time. "Baseload resources" is a technology-neutral term and refers to generation resources that would be most often called upon to meet baseload demand. Some generators—often coal and nuclear—have historically operated to meet baseload demand; however, that historical practice has generally been a reflection of plant cost structure rather than any technological capability to operate in the face of or in response to high-impact, low-probability events. Particularly before the recent drop in natural gas fuel prices, coal and nuclear plants had relatively low variable costs and relatively high startup and shutdown costs, and so had been most economic to meet baseload demand.[195] But as natural gas prices have fallen, efficient natural gas-fired plants have more often been the cost-effective option to meet baseload demand. And as demand remains relatively flat while the level of variable resources (such as wind and solar, which generate only when it is sunny or windy) increases,[196] the electric system may not need as many generators to run continuously and may instead benefit more from dispatchable resources that can supply electricity when the variable resources do not. Whether a plant has operated as baseload, therefore, is not a resilience attribute; it is just a feature of the cost structure of electricity generation. As a result, retirement of units that historically operated as baseload resources does not necessarily reflect reduced resilience of the generation system, let alone the electric system as a whole.

Change in generation by fuel type during a high-impact event.[197] Whether a certain type of generator increases its generation during a high-impact event does not necessarily reflect that it possesses attributes that would help it to perform during future such events. Rather, it may reflect the fact that high-impact events cause electricity prices to rise, and that the facility was likely to operate only during periods of high electricity prices due to high generating costs. For example, during the 2018 "bomb cyclone," coal units were available to meet unexpectedly high electricity demand because their relatively high costs meant they were not being dispatched before the event and therefore had unused generating capacity. Once electricity prices rose, it became economic to dispatch these plants. It was these market dynamics and not any particular resilience attributes of the plants that dictated their operation.[198]

Because Resilience Is a Feature of the Electric System, Focusing Only on Generation Resilience Is Improper

Trump Administration coal and nuclear support proposals have been targeted at improving *generation* resilience. Yet, even if policies to limit the retirement of existing coal and nuclear units did improve generation system resilience, such policies would not necessarily improve *system* resilience. Most outages result from disruptions in the distribution and

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[194] DOE NOPR at 46,943.

[195] *See* DOE Staff Report at 38.

[196] *Id.* at 16.

[197] Peter Balash et al., Nat'l Energy Tech. Lab, Reliability Resilience and the Oncoming Wave of Retiring Baseload Units 12-18 (2018), https://www.netl.doe.gov/energy-analyses/temp/ReliabilityandtheOncomingWaveofRetiringBaseloadUnitsVolumeITheCriticalRoleofThermalUnits_031318.pdf.

[198] *See* Karen Palmer et al., *Understanding Grid Resilience Implications for Market Design: Beyond the NETL Study*, UtilityDive (Apr. 24, 2018), https://www.utilitydive.com/news/understanding-grid-resilience-implications-for-market-design-beyond-the-ne/522052.

transmission systems, leading some analysts to advocate for a primary focus on distribution and transmission resilience policies and investments.[199] Resilience-focused policy should be evaluated with respect to system resilience, not the resilience of a single component of the system.

Resilience Policies Should be Evidence-Based and Justified Using Cost-Benefit Analysis

The Trump Administration proposals provide stark examples of the need for evidence-based policymaking to improve grid resilience. Neither the DOE NOPR, nor the contemplated DOE emergency action included a comprehensive analysis of the benefits or costs of the proposed actions. A number of analyses showed significant economic costs associated with the DOE NOPR. For example, the independent, nonpartisan think tank Resources for the Future developed a limited economic analysis of the DOE NOPR showing that the proposal would result in net economic costs of around $10 billion per year.[200] Modeling conducted by both The Brattle Group and by Energy Innovation Policy & Technology LLP arrive at similar cost estimates.[201] Yet, DOE presented no evidence that the expected value of resilience benefits of these actions would exceed $10 billion per year. Similarly, a preliminary analysis of the DOE emergency action by The Brattle Group estimated it would cost consumers $20 billion to $70 billion over two years in increased energy costs.[202] This increase would be in addition to the $4-$9 billion of welfare loss over two years caused solely by increased conventional pollution and greenhouse gas emissions, as estimated by a recent Resources for the Future analysis.[203] The Trump Administration should adopt federal policies to enhance resilience only if the benefits of doing so exceed the costs. The cost-benefit analysis framework described in this report provide the tools for doing so.

Resilience Improvements Based on Changing Generation Incentives Should Be Made Using Market-Based, Not Cost-Based Compensation

One feature of both the DOE NOPR and the emergency action DOE is currently contemplating is that they would provide targeted resources with compensation based on their costs of operation (cost-based compensation) rather than the value that they provide the system, as determined by the market (market-based compensation). As described above, the use of cost-based compensation will not provide efficient resilience-enhancing entry, exit, and operational incentives for generators, and might significantly distort the existing energy markets. Rather, market-based compensation schemes should be used for policy designed to enhance resilience by changing generator incentives. Grid operators are currently in the process of implementing or developing market-based systems to value the resilience benefits of fuel-security.[204] Getting the design details right for these schemes is critical, and many have criticized the methodologies and assumptions

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[199] Silverstein et al. at 6.

[200] Daniel Shawhan & Paul Picciano, *Costs and Benefits of Saving Unprofitable Generators: A Simulation Case Study for US Coal and Nuclear Power Plants*, RF WP 17-22 (Nov. 30, 2017), http://www.rff.org/files/document/file/RFF-WP-17-22.pdf.

[201] Metin Celebi et al, Brattle Group, Evaluation of DOE's Proposed Grid Resilience Pricing Rule (Oct. 2017), http://files.brattle.com/files/11635_evaluation_of_the_does_proposed_grid_resiliency_pricing_rule.pdf; Robbie Orvis et al, The Department of Energy's Grid Resilience Pricing Proposal: A Cost Analysis (Oct. 2017), http://energyinnovation.org/wp-content/uploads/2017/12/20171025_Resilience-NOPR-Cost-Research-Note-UPDATED.pdf.

[202] Metin Celebi et al, The Brattle Group, The Cost of Preventing Baseload Retirements (2018), https://info.aee.net/hubfs/Brattle_AEE_Final_Embargoed_7.19.18.pdf.

[203] Daniel Shawhan & Paul Picciano, Retirement and Funerals: The Emissions, Mortality, and Coal-Mine Employment Effects of a Two-Year Delay in Coal and Nuclear Power Plant Retirements, RFF WP18-18 (2018), http://www.rff.org/files/document/file/RFF%20WP%2018-18.pdf.

[204] *See, e.g.* PJM Fuel Security Proposal; *ISO New England Inc.*, 164 FERC ¶ 61,003 (2018) (ordering ISO-NE to develop a market-based fuel security construct).

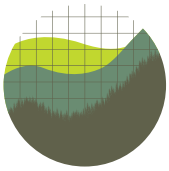
that are being used to develop these market-based schemes.[205] But if done right, market-based compensation is preferable to cost-based compensation for the procurement of real resilience-enhancing grid services.[206]

Conclusion

States and the federal government have a range of authorities to direct investments, implement policies, and facilitate coordination in order to enhance electric system resilience. These authorities can be used to implement a wide variety of actions that help the grid defend against, absorb, or recover from high-impact, low-probability shocks. However, the exercise of these authorities should be consistent with the concept of resilience described in this report and should be evaluated using the cost-benefit framework presented here. By doing so, state and federal regulators will ensure that potential investments and policies enhance the resilience of the electric system as a whole, and that the resilience improvements caused by those policies are justified by their costs.

[205] Kathiann M. Kowalski, *Critics: PJM Fuel Security Plan Ignores Renewables, Won't Build Resilience*, Energy News Network (May 9, 2018), https://energynews.us/2018/05/09/midwest/critics-pjm-fuel-security-plan-ignores-renewables-wont-build-resilience/; Paul Peterson et al, Synapse Energy Economics Inc., Understanding ISO New England's Operational Fuel Security Analysis (2018), https://www.clf.org/wp-content/uploads/2018/05/Understanding-ISO-NE-OFSA1.pdf.

[206] *See* FERC Resilience Order, 162 FERC ¶ 61,012 at PP 11, 16 (rejecting DOE Resilience Pricing, in part, because it used disfavored cost-of-service compensation rather than market-based compensation); *ISO New England Inc.*, 164 FERC ¶ 61,003 at 3 (Glick, Comm'r, *dissenting in part*) (arguing that FERC's preliminary action on fuel security for a natural gas plant would cause "a parade of uneconomic generators seeking cost-of -service rate treatment under the guise of fuel security" rather than "reform [of] the ISO-NE market to address the drivers of whatever fuel security problem may exist"); *Constellation Mystic Power, LLC*, 164 FERC ¶ 61,022 at 1-2 (2018) (Powelson, Comm'r, *dissenting*) (arguing that FERC should have rejected an cost-of-service agreement for a facility in favor of waiting for stakeholders to develop a market-based solution to fuel security concerns).



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New York University School of Law
Wilf Hall, 139 MacDougal Street, New York, New York 10012
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