Stakeholder Dialogue

INCREASING EMISSIONS CERTAINTY UNDER A CARBON TAX

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INTRODUCTION

Various organizations and individuals, including issue-oriented advocacy groups, research institutes, business groups, and members of Congress, have recently proposed that the United States consider use of a carbon tax as the primary federal policy to reduce greenhouse gas emissions.[1] A carbon tax establishes a fixed fee per unit of emissions and thereby provides a certain price incentive to cut emissions.[2] However, one concern regarding a carbon tax is that it does not ensure that the nation will achieve a specific emissions goal because the economy's response to such a tax is unknowable in advance.[3] This concern mirrors the reciprocal apprehension over allowance-price uncertainty (and ultimately cost uncertainty) under a cap-and-trade

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[1] *See, e.g.*, American Opportunity Carbon Fee Act of 2015, S.1548, 114th Cong. (2015) (proposing a federal fee on fossil fuel products producing carbon dioxide as well as other greenhouse gas emissions, including methane); Adele C. Morris, *Proposal 11: The Many Benefits of a Carbon Tax*, *in* 15 WAYS TO RETHINK THE FEDERAL BUDGET 63–69 (2013) (proposing "a modest carbon tax to finance reforms to the U.S. tax system to promote economic growth, reduce budget deficits, reduce redundant and inefficient regulation, reduce unnecessary subsidies, and reduce the costs associated with climate change"); JERRY TAYLOR, NISKANEN CENTER, THE CONSERVATIVE CASE FOR A CARBON TAX 15–27 (2015), https://perma.cc/ZTG2-YY5G (reviewing Adele Morris's proposal from a conservative point of view); *Carbon Fee and Dividend Policy*, CITIZENS' CLIMATE LOBBY, https://perma.cc/2X8K-STYQ (proposing "a national, revenue-neutral carbon fee-and-dividend system" as the organization's preferred climate solution); *Climate 2.0: Fact Sheet*, PARTNERSHIP FOR RESPONSIBLE GROWTH, https://perma.cc/8VUH-Y4JT (discussing the "merits of a simple carbon fee" while offering "a pro-growth solution"). The U.S. Department of the Treasury also recently released a paper outlining a methodology for analyzing a carbon tax. JOHN HOROWITZ ET AL., U.S. DEPT. TREASURY, METHODOLOGY FOR ANALYZING A CARBON TAX 13–14 (2017), https://perma.cc/SG3G-BZMG (pointing to policy provisions for "responding to real-world outcomes" as a design option for a carbon tax).

[2] This Essay uses the term "carbon tax" to denote a tax on greenhouse gas emissions without taking a particular stand on which greenhouse gases the tax would cover.

[3] *See* Richard G. Newell & William A. Pizer, *Regulating Stock Externalities under Uncertainty*, 45 J. ENVTL. ECON. & MGMT. 416, 418 (2003) ("When uncertainty exists about costs, and policies must be fixed before the uncertainty is resolved, priced policies will lead to distinctly different outcomes than quantity policies"); Marc J. Roberts & A. Michael Spence, *Effluent Charges and Licenses under Uncertainty*, 5 J. PUB. ECON. 193, 194 (1976) ("Effluent charges and marketable licenses have the virtue of inducing the private sector to minimize the costs of cleanup. But in the presence of uncertainty, they differ in the manner in which the ex post achieved results differ from the socially optimal outcome."); Martin Weitzman, *Prices vs. Quantities*, 41 REV. ECON. STUDIES 477, 480 ("If there is any advantage to employing price or quantity control modes, therefore, it must be due to inadequate information or uncertainty").

program, which does provide for a certain emissions outcome. Moreover, just as policy mechanisms can increase price certainty under a cap-and-trade program,[4] so too can policy mechanisms increase emissions certainty under a carbon tax.

Ultimately, there is an underlying tradeoff between certainty about emissions and certainty about prices and costs. To reduce uncertainty about whether a tax will achieve specific emissions goals, additional mitigation measures could be called upon if emissions exceed those goals. However, such additional measures introduce uncertainty about costs. At the extreme, a commitment to achieve emissions targets at all costs would imply that costs could be quite high. Discussions of policy mechanisms to increase price and cost certainty under several current cap-and-trade programs confronted this same dilemma: how much uncertainty about emissions outcomes is acceptable given reciprocal uncertainty about costs?[5]

Viewed through a slightly different lens, mechanisms that balance emissions and cost uncertainty can be viewed as a way to structure a more careful compromise between cost concerns and environmental interests. Under a cap-and-trade program, a price ceiling or allowance reserve may allow economic interests to agree to what may be viewed as an economically risky cap with the assurance that further steps will be taken should prices become too high. Similarly, under a carbon tax, mechanisms that can increase mitigation action may allow environmental constituencies to agree to what they may view as an environmentally risky tax with the assurance that further steps will be taken should emissions become too high.

This Essay discusses a range of mechanisms that could increase emissions certainty under a carbon tax. It draws from recent discussions between the authors and other policy experts, and its goal is to define a set of options for deeper exploration. Other Essays in the Symposium explore specific proposals related to one of these ideas, automatic adjustments to the tax rate.[6]

Here, we begin with a discussion of how to measure emissions performance, or what it means to be achieving or not achieving an emissions goal. This performance could provide the basis for pursuing remedial mechanisms. Next, the Essay presents a taxonomy of such mechanisms and the challenges and opportunities of each. It discusses ideas for initiating these mechanisms, either through some automated or discretionary procedure. The Essay concludes with a summary of areas for additional research.

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[4] *See* JAN MAZUREK ET AL., NICHOLAS INST. FOR ENVTL. POL'Y SOLUTIONS, CONQUERING COST: OPTIMAL POLICY APPROACHES TO THE COST OF CLIMATE CHANGE WORKSHOP 4–5 (2009), https://perma.cc/8GKZ-CLYT; Harrison D. Fell et al., *Soft and Hard Price Collars in a Cap-and-Trade System: A Comparative Analysis*, 64 J. ENVTL. ECON. & MGMT. 183, 183–85 (2012); Brian Murray et al., *Balancing Costs and Emissions Certainty: An Allowance Reserve for Cap-and-Trade*, 3 REV. ENVTL. ECON. & POL'Y 84, 86–89 (2009); Adele Morris et al., *Time for a Price Collar on Carbon*, BROOKINGS (July 24, 2009), https://perma.cc/Z68J-TK8M; Darren Samuelsohn, *Behind 'Safety Valve' Debate Resides 30+ Years of History*, E&E NEWS (Mar. 11, 2008), https://perma.cc/2H9N-WBCA.

[5] See sources cited *supra* note 4.

[6] *See* Joseph E. Aldy, *Designing and Updating a U.S. Carbon Tax in an Uncertain World*, 41 HARV. ENVTL. L. REV. F. 28 (2017); Marc Hafstead et al., *Adding Quantity Certainty to a Carbon Tax Through a Tax Adjustment Mechanism for Policy Pre-Commitment*, 41 HARV. ENVTL. L. REV. F. 41 (2017).

I. MEASURING EMISSIONS PERFORMANCE

What does it mean to decide whether the country is achieving an emissions goal after some period of time? Emissions goals are at times expressed as targets for a particular year. Indeed, the goal of the U.S. in the Paris Agreement is to achieve an emissions reduction of twenty-six to twenty-eight percent below 2005 levels in 2025.[7] In this context, the most obvious definition of achieving or not achieving the target would be whether emissions in 2025 exceed this range. This raises two issues: (1) whether emissions in a single year is the best indicator of achievement for an emission adjustment mechanism, and (2) how projections of future emissions might affect an interim assessment of achievement.

Greenhouse gases are stock pollutants whose impacts depend on accumulated atmospheric concentrations. Moreover, emissions can be high or low in any single year for a variety of reasons, including weather, economic cycles, accidents, or other unforeseen events. For these reasons, defining success or failure on the basis of performance in a single year could lead to inappropriate conclusions about environmental impact.[8] For an emission adjustment mechanism, a single-year goal can create unnecessary disruption—adjustments may be made, but then need to be reversed. Much of the short-term emissions volatility will tend to average out over a number of years without requiring any (or as frequent) interventions to achieve a desired environmental outcome. That is, it is this average emission level over longer periods of time—accumulated emissions—that matter for the environment.

A focus on multi-year average emission outcomes avoids these issues. Virtually all programs with compliance regimes include multi-year targets. For example, the Kyoto Protocol set a goal that measured performance on the basis of average emissions over five years (2008–2012).[9] Even with annual targets, programs often define compliance over a longer window. The 2009 Waxman-Markey Bill, passed by the House of Representatives, used a two-year window and allowed costless borrowing of the following year's emissions allowances.[10] The European Union Emissions Trading System similarly allows the circulation of future vintage allowances for compliance, so long as they are from the same five- to eight-year trading period.[11] The Regional Greenhouse Gas Initiative has three-year compliance periods.[12] All of these programs allow emission permits to be banked for future use if they are not used during the year issued. This

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[7] U.S. COVER NOTE, INDC AND ACCOMPANYING INFORMATION, UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE (2015), https://perma.cc/6WL4-H8N5.

[8] *See* Michael Lazarus et al., *Single-Year Mitigation Targets: Unchartered Territory for Emissions Trading and Unit Transfers*, 4–11 (Stockholm Env't. Inst., Working Paper No. 2014-01, 2014), https://perma.cc/Y4ZD-VW2K.

[9] Kyoto Protocol to the United Nations Framework Convention on Climate Change art. 3, ¶ 8–9, Dec. 10, 1997, 37 I.L.M. 22.

[10] The American Clean Energy and Security Act of 2009, H.R. 2454, 111th Cong. §§ 702, 722–725 (2009).

[11] A. DENNY ELLERMAN & PAUL J. JOSKOW, THE EUROPEAN UNION'S EMISSIONS TRADING SYSTEM IN PERSPECTIVE 3 (2008), https://perma.cc/9YQ8-UJ6A.

[12] MODEL RULE, REG'L GREENHOUSE GAS INITIATIVE 13 (2013), https://perma.cc/KH8W-L8RK.

further emphasizes cumulative, rather than annual, emission levels as the targeted outcome.

In addition to a multi-year performance metric, the choice about whether to make an adjustment and, if so, how to tailor it, should consider any additional knowledge about likely *future* emissions. For example, suppose emissions were two percent above the stated emissions goal for several years. This overage might typically demand an adjustment. But whether and how much to adjust would likely be different if this deviation were projected to grow, shrink, or stay the same given emerging technological and market conditions. That is, the response might be different if nuclear power facilities were slated to come online in the very near future and replace a large number of coal units, dramatically reducing emissions, versus a situation where such activity is not anticipated.

Moving beyond the conceptual question of what time window or windows to use, there is also the question of data. Policymakers will need to decide on which emissions data they rely on to measure current performance as well as which models, if any, should be used for projecting future emissions. One source for historic emissions may be the national greenhouse gas inventory,[13] and one source for projections may be government forecasts such as those produced by the U.S. Energy Information Administration ("EIA").[14] It will be important to ensure that selected sources are up to the task. This includes ensuring that the timing of the release of nationally aggregated emissions data and of emissions projections is aligned with the timing of any performance measures used to make policy adjustments. It also includes ensuring the programs' reliability, accuracy, and disclosure policy is sufficiently robust to drive market-based policy interventions with potentially significant financial consequences.

II. MECHANISMS TO INCREASE THE EMISSIONS CERTAINTY OF A CARBON TAX

If emissions outcomes under a carbon tax are above or below a chosen performance goal, policy makers have several policy mechanisms they could use to guide the emissions level toward the goal. These mechanisms include changing the tax rate or schedule, using traditional regulatory tools as a backup to the tax, using revenue to pay for additional emission reduction activities, or applying hybrid approaches that combine elements of all three.

A. Tax Adjustments

One approach to increase emissions certainty with a carbon tax would be to adjust the tax rate to reflect updated information about greenhouse gas emissions performance. This adjustment could occur on the basis of a predetermined formula or on a more ad hoc

[13] The EPA submits the national greenhouse gas inventory to the United Nations in accordance with the Framework Convention on Climate Change. *See* EPA, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990–2014 (2016) ("Under decision 3/CP.5 of the UNFCCC Conference of the Parties, national inventories for UNFCCC Annex I parties should be provided to the UNFCCC Secretariat each year by April 15."), https://perma.cc/A253-MGCT.

[14] *See, e.g.*, U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2017 (2017), https://perma.cc/67LU-RJVN.

basis. With a predetermined formula, legislators would decide up front how the tax would change over time and in response to established performance metrics. With an ad hoc adjustment, Congress would first establish the emissions performance goals and an initial trajectory for the tax rate over time. Then, either Congress or a delegated agency would review emissions performance and determine the necessary adjustments to achieve the stated performance goals in the future. An adjustment using a predetermined formula is discussed here; the idea of a more discretionary approach is discussed below in the context of triggering mechanisms.

A predetermined formula would need to specify the exact timing and method of a tax rate adjustment as well as the performance metrics used to determine the adjustment. The adjustment could be relatively simple. For example, the tax schedule might include pre-determined high and low paths for the tax rate, along with conditions under which the actual tax rate path would switch from one to the other. The tax might start on the low path, but if emissions were deemed too high relative to the established goal, the tax rate would switch to the high path. In economic policy, there is a long history of such operational models in which an initial default path is maintained until a threshold is reached that justifies a large, discrete adjustment.[15] This type of adjustment—one in which there are fewer, relatively large changes in the tax rate rather than more frequent, smaller changes—is preferred when there are fixed costs associated with any changes in the tax rate. For a carbon tax, such fixed costs could include the additional time and resources for businesses to consider and respond to a tax change. That is, they would need to bring in accountants, engineers, and business experts to adjust their activities, which would have an associated cost every time the path of expected tax rates is adjusted.

More complex rules for guiding the adjustments might also exist. Such rules might allow triggering events based on a wider set of performance indicators along with more gradations in the tax rate change. In determining whether simple or more complex rules are preferable, it will be important to consider the objectives of the policy. In addition to increasing emissions certainty, it will be valuable to limit the volatility of the tax rate. As noted earlier, this is partly a fundamental trade-off between certainty about emissions and cost. Uncertainty introduced by frequently adjusting the tax rate can drive up business costs.[16] Regardless of the trade-off chosen, one can strive to make the rules transparent, predictable, and easy to understand. It will also be important to consider whether adjustments are symmetric: if the tax rate can adjust up when emissions are above the established goal, can it also adjust down when emissions are below it (or cease to be above it)?

In the context of the tradeoff between emissions and cost certainty, there is the question of the degree and type of emissions certainty that is desired. If the objective is to move emissions closer to a goal when they are otherwise too high, it might be sufficient to have simply a high and low path for the emissions tax. However, a high and low path

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[15] Here, we are referring to the (S,s) model in economics, first applied to the problem of inventory control in Kenneth J. Arrow et al., *Optimal Inventory Policy*, 19 ECONOMETRICA 250 (1951). For a recent review, see Andrew Caplin & John Leahy, *Economic Theory and the World of Practice: A Celebration of the (S,s) Model*, 24 J. ECON. PERSPECTIVES 183 (2010). This model applies to a situation where there are fixed costs to making any policy change, large or small.

[16] *See generally* AVINASH K. DIXIT & ROBERT S. PINDYCK, INVESTMENT UNDER UNCERTAINTY (1994).

may be insufficient if the goal is to ensure with a greater probability that the U.S. meets an explicitly defined emissions target. In this case, unless there is willingness to allow the high tax rate path to be quite high, it might be more appropriate to make sequential adjustments as necessary without raising the tax more than required to achieve the emissions target. Put another way, a system designed for fine-tuning might have to adjust the tax more frequently by smaller amounts on the basis of smaller deviations from the emissions goal. Thinking through these choices—what triggers the adjustment, how large it is, and what constraints should be placed on its frequency—are important policy design questions as well as ripe topics for further research.[17]

A number of relevant precedents for automatic policy adjustments based on observed outcomes exist. Marginal income tax rates vary based on individuals' income. Borrowing this idea, we could apply the principal to the country as a whole under a carbon tax. A simple formula could set the carbon tax rate to rise with aggregate emissions across the U.S. economy. The government would assess a higher tax rate as national U.S. emissions grow larger, rather than simply with the passage of time. Many income-support payments as well as tax brackets and exemptions are automatically adjusted on the basis of inflation indexes. In trade, tariff-rate quotas allow a certain amount of imports with limited or no tariff.[18] If imports exceed the quota, a tariff or upward tariff adjustment is applied. The Taylor Rule[19] provides a formulaic guide for central banks to adjust interest rates in response to specific changes in inflation, unemployment, or gross domestic product, though the formula is not necessarily codified in central bank rules.[20] As noted in the introduction, formulaic adjustments to a carbon tax are analogous to the price collar/allowance reserve approach under a cap-and-trade system, and these adjustments thus have precedent in alternative carbon-pricing systems now in operation.[21]

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[17] *See* Marc Hafstead et al., *Adding Quantity Certainty to a Carbon Tax Through a Tax Adjustment Mechanism for Policy Pre-Commitment*, 41 HARV. ENVTL. L. REV. F. 41 (2017) (examining how a mechanism to provide greater emissions certainty might be designed, what its key elements would be, and what modeling might be undertaken by economists to better understand the implications of such a policy design).

[18] *See generally* 19 U.S.C. § 3601 (2012); DAVID W. SKULLY, U.S. DEP'T OF AGRIC., ECONOMICS OF TARIFF-RATE QUOTA ADMINISTRATION (2001), https://perma.cc/HC3A-LDXT (analyzing tariff-rate quota administration in the United States in the context of the Uruguay Round Agreement of the World Trade Organization's Uruguay Round Agreement on Agriculture).

[19] *See* John B. Taylor, *Discretion Versus Policy Rules in Practice*, 39 CARNEGIE-ROCHESTER CONF. SERIES PUB. POL'Y 195, 199–203 (1993); *see also* Athanasios Orphanides, *Historical Monetary Policy Analysis and the Taylor Rule*, 50 J. MONETARY ECON. 983 (2003); Athanasios Orphanides, *Monetary Policy Rules Based on Real-Time Data*, 91 AM. ECON. REV. 964 (2001); Michael Woodford, *The Taylor Rule and Optimal Monetary Policy*, 91 AM. ECON. REV. 232 (2001).

[20] Recently, there has been talk of an alternative central bank rule to target an interest rate that is "neither expansionary nor contractionary." *See* Donald Luskin, *Yellen Gives Conservatives Something to Cheer*, WALL ST. J. (Feb. 16, 2017), https://perma.cc/X559-V4CD.

[21] *See* CAL. CODE REGS. tit. 17, § 95914 (2017); MODEL RULE, REGIONAL GREENHOUSE GAS INITIATIVE 13 (2013), https://perma.cc/4UP7-2ERT; CAL. AIR RES. BD., STAFF REPORT: INITIAL STATEMENT OF REASONS PROPOSED REGULATION TO IMPLEMENT THE CALIFORNIA CAP-AND-TRADE PROGRAM app. at G-5 to G-9 (2010), https://perma.cc/PC4Q-7XRS; *see also* Richard Schmalensee & Robert Stavins, *Lessons Learned from Three Decades of Experience with Cap-and-Trade* 10, 12, 17 (Harvard Kennedy School, Faculty Research Working Paper 15-069, 2015), https://perma.cc/CV3D-2X7A (analyzing major existing emissions trading programs to draw implications for future applications of this policy).

The biggest challenge to the formulaic approach is the added complexity of establishing not just the initial path of the tax rate, but the various performance metrics and responses. Given these parameters must be established upfront, agreement on their levels might bog down a deliberative process. Additional research could shed light on how different adjustment approaches work when applied to historic or future-simulated data.

The biggest advantages of this approach are its transparency and potential to tailor the parameters to deliver the desired degree of certainty. These advantages are analogous to those of price collars (floors and ceilings), which are similarly transparent and tailored to such preferences under a cap-and-trade program.

B. Regulatory Tools

A second potential mechanism to promote emissions certainty is to make use of various regulatory tools as a backup to the carbon tax. This approach would initiate one or more regulatory programs if the United States failed to meet its performance goals with the carbon tax. If legislators decide to use such regulatory tools, they could choose from multiple options. This includes use of existing mechanisms under the Clean Air Act, modification of those mechanisms, or creation of an entirely new regulatory mechanism.

For example, suppose a carbon tax were implemented as a replacement for regulation under EPA's existing authority under the Clean Air Act. One approach would be to reinstate that existing authority and to use the associated regulatory tools if emissions fail to meet necessary performance goals. Under such an approach, the federal government implements a carbon tax. In parallel, the EPA constructs a regulatory program to achieve emissions reductions as envisioned under existing authority. Under the cooperative federalism principles of this authority, such actions will have to consider state goals and implementation of regulatory plans for emission reductions. The EPA would activate this program, however, only in the event of a finding that the U.S. has failed to meet its emissions goals with the carbon tax.

The Clean Power Plan has an analogous policy model using a parallel backup plan. Under the Clean Power Plan, states could opt for a "state measures" plan to meet federal emission goals. However, states choosing this route must also create a federally enforceable backup plan. In the event that the "state measures" plan does not meet the Clean Power Plan's emissions targets, the federally enforceable backup plan would be activated.[22] This approach turns to a federal plan when the state plan fails. In comparison, the carbon tax example could turn to a state- or federally-enforced regulatory program if the federal carbon tax failed.

A second approach would be to modify the Clean Air Act in a way that provided more flexible regulatory authority if emissions performance goals were not met under the carbon tax. Under this approach, Congress could modify EPA's authority to enact regulation state-by-state and sector-by-sector under Section 111. This might include

[22] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 40 C.F.R § 60.5740(3) (2017).

explicit authority to make use of flexible regulations that span source categories, sectors, and/or states. Or, the modifications could suggest a particular approach, such as a national tradable performance standard for the power sector or a cap-and-trade system spanning multiple sectors.

If one of the goals of a carbon tax is to achieve a particular emissions goal that could be reached using regulations under the Clean Air Act, there is a simple logic to reinstating the suspended regulatory approach should a carbon tax fail to achieve that goal. However, except in rare cases such as the statutory sulfur dioxide cap (8.9 million tons),[23] the Clean Air Act generally does not legislate a particular emissions cap or goal. Thus, the choice of a Clean Air Act-justified emissions goal for carbon dioxide and other greenhouse gases could be contentious if such a quantitative target were put into new carbon tax legislation. This contention could arise even if the target is exclusively for the purpose of triggering additional regulation.

Moreover, some stakeholders are looking to a carbon tax as a replacement for either a Clean Air Act-based regulatory program or an economy-wide cap-and-trade program. This motivation may make such regulatory options in response to emissions target shortfalls less appealing to those stakeholders. In addition, while the idea of modifying existing regulatory authority to allow flexible, less expensive regulation might look like a reasonable compromise, it may not turn out that way. In particular, it may be difficult to make changes to the Clean Air Act without opening the whole statute to amendment. This, in turn, could quickly turn into a quagmire among various stakeholders, particularly between businesses and environmental and public health interest groups. Even small amendments to the Clean Air Act could make the congressional committee process considerably more complicated.

Unlike the tax adjustment mechanism, a regulatory tools approach does not lend itself to fine-tuning. Nor is there symmetry: it would be difficult to undo the regulation if the emissions goal is overachieved after various regulatory tools are implemented. Given this challenge, it may make sense to be more cautious when deciding how such regulation is triggered. In other words, policy makers choosing this approach might establish a trigger that reflects a larger and more persistent deviation from the emission goal than a trigger associated with a reversible tax adjustment.

C. Revenue Spending

In addition to tax rate adjustments and regulatory tools, if emissions are higher than expected then legislators could use part of the revenue from a carbon tax to fund programs that provide financial support for mitigation within or outside the sectors covered by the carbon tax. This method is similar to offset mechanisms under a cap-and-trade program, particularly if the mitigation achieved through this financial support is designed to exactly negate the emissions that exceed an established emissions goal. However, because the revenue programs would be based on government procurement rather than private sector trading, this mechanism operates quite differently than a traditional offset program. In particular, the government has the ability to scrutinize and

[23] 42 U.S.C. § 7651b(a)(1) (2012).

adapt to developments in the supply of mitigation projects. It is possible that such procurement guidelines might encourage better quality projects, i.e., greater assurance that emission reductions are real and verifiable.[24]

Unlike tax rate adjustments or regulatory tools, this mechanism requires government expenditure when triggered. However, the revenue requirement arises when emissions—and hence carbon tax revenue—exceed the original goal. Moreover, the unexpected revenue could be more than enough to support offsetting mitigation projects because mitigation options outside the sectors covered by the tax are often cheaper than those within sectors covered by the tax. For example, changes in forest and agricultural practices, land use changes, and methane capture, domestically and abroad, can be difficult to include in a tax (or cap-and-trade) program for practical and political reasons. At the same time, these activities often provide inexpensive mitigation options.

One appeal of this mechanism is that it imposes neither an additional regulatory burden nor increased tax rates when emissions exceed the goal. Rather, it uses the additional revenue collected from the higher emissions base to improve emissions outcomes. That distinction is an advantage for those being taxed or regulated. One question about this approach, however, is whether and how quickly such external mitigation actions might be available. Unless there are other markets where suppliers can sell mitigation when government demand is low, it may take considerable time to incentivize new mitigation activities.[25] This issue may mean that the government will need to smooth its purchases, perhaps committing to spend a portion of carbon tax revenues on an ongoing basis in order to bolster the performance of such a mitigation market. In addition to positioning the market to be responsive if significant future purchases are required, smaller, regular purchases could also create a provisional "reserve" of offsets to handle smaller emissions performance shortfalls should they occur.

Perhaps the main challenge is that the revenue spending approach still may not ensure a particular emissions outcome. If the tax rate is too low, revenue may not be sufficient to buy enough mitigation elsewhere to make up for the emissions reduction shortfall. That is, unless the government is willing to turn to sources of revenue *in addition to* the carbon tax revenue associated with excess emissions. Moreover, it may take some time to incentivize new mitigation activities and ensure they are "additional." Establishing how much of the emissions mitigation purchased through the tax revenues is additional to mitigation that would have happened anyway is difficult. The same issue arises under offset markets in a cap-and-trade programs.[26] Under cap-and-trade offset programs, a verification system is used to help ensure that the purchased offsets are the result of additional mitigation efforts that would not have otherwise occurred.[27] It is worth noting that the other main approaches discussed above also may fail to ensure a

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[24] The government can also oversee quality in cap-and-trade offset markets in a regulatory capacity, but it might be a more effective monitor as the direct buyer of the reduction unit.

[25] One possibility is the use of International Transferred Mitigation Outcomes ("ITMO"s) under the Paris Agreement. *See* Framework Convention on Climate Change, Adoption of the Paris Agreement art.6, U.N.Doc. FCCC/CP/2015/10 (Jan. 29, 2016).

[26] *See generally* Brian Joseph McFarland, *Carbon Reduction Projects and the Concept of Additionality*, 11 SUSTAINABLE DEV. L. & POL'Y 15 (2011).

[27] CAL. CODE REGS. tit. 17, § 95977 (2016) (requiring verification from a California Air Resources Board-accredited verification body for offset project data reports).

particular emissions outcome. However, they do ensure additional effort by domestic regulated entities toward that outcome. The revenue approach risks being viewed as (or being in reality) a transfer payment without much additional mitigation effort.

Two additional challenges relate to implementation of such an approach. First, legislators or the administering body must decide how to allocate spending among mitigation options. Offset and mitigation finance programs often target particular sectors outside the policy's coverage, such as forestry, agriculture, and landfills.[28] But, unlike an offset program, a revenue spending mechanism could also include spending *within* sectors covered by the tax. For example, in addition to taxing emissions from coal-fired power plants, the government could spend money to subsidize their retirement. Other programmatic expenditures could be directed to complementary programs in energy efficiency or zero-emitting power sources, such as renewables or nuclear units. Under a tax system, such expenditures decrease emissions. Under a standard cap-and-trade system, these complementary policies serve only to reduce the price needed to meet the fixed emissions target.[29]

Second, the revenue spending for mitigation approach requires new government infrastructure. This could be housed at an existing agency—such as the EPA or U.S. Department of Agriculture—or at a new agency created for this purpose. The government could also fashion a role for states in this program, one similar to federal-state responsibilities under the Clean Air Act.[30]

D. Hybrid Approaches

Two or more of the above-described mechanisms could be combined, perhaps better addressing the range of stakeholder concerns. For example, legislation could pair an adjusting carbon tax rate with a regulatory approach only as a last resort. In this situation, modest refinements could be achieved using the carbon tax rate adjustments. This approach could, on the one hand, limit the conditions wherein a regulatory approach would replace the tax, while on the other hand providing an alternative to higher tax rates if additional mitigation is needed. Although using hybrid approaches may help achieve such balance, they may also be relatively complicated to design, requiring additional consensus.

IV. ACTIVATING AN EMISSIONS CERTAINTY MECHANISM

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[28] *See, e.g.*, *id.* §§ 95970–95 (describing the offset program in California); *About the PAF*, WORLD BANK GROUP, https://perma.cc/EHW3-YVNB; *What is the CDM*, U.N. FRAMEWORK CONVENTION ON CLIMATE CHANGE, https://perma.cc/JGB2-4KET; *see also* LYDIA OLANDER ET AL., NICHOLAS INST. FOR ENVTL. POL'Y SOLUTIONS, DESIGNING OFFSETS POLICY FOR THE U.S. 16 (2008), https://perma.cc/QC6W-C72Z (noting examples of offset programs for uncapped or outside-of-regulation mitigation opportunities).

[29] ELEC. POWER RESEARCH INST., EXPLORING THE INTERACTION BETWEEN CALIFORNIA'S GREENHOUSE GAS CAP-AND-TRADE PROGRAM AND "COMPLIMENTARY" GHG EMISSIONS REDUCTION POLICIES 5-1 to 5-12 (2013), https://perma.cc/Z6M9-N2DV.

[30] *See* 42 U.S.C. § 7410 (2012) (providing for the cooperative federalism framework whereby states are able to create and manage their state's implementation of National Ambient Air Quality Standards).

When including any of the above mechanisms in a carbon tax, policy-makers will need to determine the conditions that initiate their use. Up to this point, this Essay generally assumes use of an automatic trigger, whereby actions occur automatically when a defined notion of emission performance exceeds a specified threshold. However, the activation of measures could also be discretionary. Because Congress can always undo its own laws, discretionary adjustment could be viewed as the default approach. The discretionary option also includes variations that would either delegate authority or create nuanced differences in the kind of congressional action required. Both approaches are defined and contrasted below. Given that the discussion thus far has been primarily about automatic adjustments, much of this section will emphasize specific examples of discretionary adjustment as an alternative pathway.

A. Automatic Adjustment

Any of the above mechanisms could have an automatic trigger, meaning that the enabling statute forces the mechanism to initiate under given circumstances. Using examples from the discussion of tax adjustment options above, if the emissions performance of the U.S. exceeds a predetermined emissions range in period one, the tax would automatically increase to a higher level for some specified time period beginning in period two. This approach requires no further political action to adjust the tax rate or implement whatever mechanism has been triggered. Rather, the policy can initiate automatically according to emissions data.

An established carbon tax and automatic adjustment mechanism provide transparency to firms and individuals about what will happen in the future. On the other hand, unforeseen events and new information could make automatic adjustments unnecessarily disruptive. Therefore, a well-defined but discretionary approach may be more appealing under certain circumstances.

B. Discretionary Adjustment

A well-defined discretionary approach would specify a timeline, process, and guidance for Congress or a delegated agency to implement some combination of the mechanisms described above. By defining the parameters that affect a discretionary decision, firms and individuals can be well-informed about the timing and possible size of a policy adjustment even if the exact outcome remains uncertain.

Although Congress always has the option to adjust a tax or institute a regulatory program through new legislation, one discretionary approach would require regular congressional review of the carbon tax to ensure it is achieving its stated objectives. This review could be undertaken in lieu of, or in tandem with, an automatic adjustment. For example, the initial legislation could mandate that if Congress failed to implement an update, the automatic mechanism would proceed subject to the specified performance and response parameters.[31]

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[31] An example of this type of mechanism is the Medicare "doc fix" legislation to delay implementation of the Medicare Sustainable Growth Rate ("SGR"). Balanced Budget Act of 1997, Pub. L. No. 105-33, 111 Stat. 251 (1997). The SGR was meant to limit Medicare spending, but because of the rate of healthcare spending, using

Another alternative is to delegate carbon tax adjustment authority to an agency. This option would allow an Executive Branch agency or independent commission to determine whether and how to implement a particular mechanism on the basis of data on the effects of the program and other extenuating factors. This approach parallels the 2009 Waxman-Markey Bill's recommendation of a carbon market board that would have, among other things, been charged with protecting against price uncertainty in the carbon market.[32] Such a body would provide flexibility for dealing with unanticipated changes in circumstances or with policy indicators beyond those anticipated when the legislation is passed. By delegating carbon tax adjustment authority to an agency, policy could adapt to changes in our understanding of climate change impacts and risks as well as to economic developments and other world events.

One question with this approach, however, is whether Congress would pass legislation providing an agency with the authority to change carbon tax rates or implement other adjustment mechanisms.[33] In part, the question may be whether the balance of emissions and economic concerns are sufficiently resolved to define clear objectives for the delegated authority. Such objectives are clear, for example, for the Federal Reserve Board in managing monetary policy, namely full employment and stable prices. Regarding climate change, it is not clear that all parties would be able to agree on similar objectives. There may be agreement on a particular carbon tax level and emissions goal, but if that level and goal prove incompatible, there may not be agreement about how much the emission goal should be sacrificed or the carbon tax should be raised. If Congress cannot resolve such high-level issues about the burden and benefit of climate change policy, it is unclear why Congress would be willing to delegate that decision to an agency.

V. FUTURE RESEARCH AREAS

Drawing upon these different ideas, a research roadmap emerges that could inform future carbon tax design.

Broadly speaking, a deeper review of relevant precedents would be useful, including precedents for articulating environmental or other purposes in tax legislation; for different adjustment mechanisms in domestic and international fees; and for congressional delegation of authority over tax rates and schedules. Such a review can help identify cases in which similar efforts were made to blend dual objectives and conditional adjustments into legislation to both clarify issues of legal precedent and assess efficacy.

In terms of measuring emissions performance, it would be useful to research the best way to recognize persistent versus transitory emissions deviations in order to

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the SGR would have cut reimbursement to doctors. In other words, without legislation, each year, the SGR would go into effect and cut payments to doctors. Thus, to prevent this outcome, Congress needed to pass a bill delaying the SGR's implementation. *See Congress Repeals Medicare 'Doc Fix Law,' Ending Annual Scramble*, NPR (Apr. 16, 2015), https://perma.cc/8VES-MB6N. Here, the carbon tax, similar to the SGR, would automatically adjust unless Congress acted to prevent or change the adjustment.

[32] H.R. 2454, 111th Cong. § 726 (2009).

[33] For an examination of whether Congress can delegate tax authority to an agency or independent commission, see James R. Hines Jr. & Kyle D. Logue, *Delegating Tax*, 114 MICH. L. REV. 235, 241–48 (2015).

determine the necessity and timing of any adjustments. Furthermore, current sources of emissions data, projections, or both may need upgrades to be suitable for regulatory activities. It will be important to review their timing, comprehensiveness, reliability, and disclosure procedures, among other possible concerns.

Regarding the use of tax adjustments in response to emissions outcomes, one question is how one might define an "optimal" policy based on minimizing emission uncertainty subject to a limit on adjustment costs. Research could also explore other options for determining the adjustment trigger, size, time interval, and frequency.

Looking at regulatory tools as a backup to carbon tax performance, one question is how/whether the triggering event for such a mechanism should differ from those considered for a tax adjustment. Another is whether there are adjustments to the Clean Air Act that might be acceptable to all parties as part of such a mechanism. Finally, we noted earlier that a regulatory mechanism is difficult to tailor in the same way one can fine tune emission outcomes by finely-tuned tax adjustments. Future research might look for ways around this.

Revenue spending mechanisms to procure additional emissions mitigation raise different questions. It will be important to review what we know from experience to date regarding existing offset and mitigation purchase programs. This includes questions of additionality, what kind of opportunities might be pursued, and where such a program would be housed. Then there are unique possibilities raised by a tax: might some revenue be spent to further encourage mitigation among taxed activities? Does there need to be some revenue allocated to such activities, regardless of emission outcomes, in order to create a market in advance of the potential need? Or might other markets (for example, the internationally transferred mitigation outcomes under the Paris Agreement)[34] be tapped?

Finally, further research could examine how timelines, processes, and guidance might make discretionary adjustments more predictable and less disruptive for those most impacted by the carbon tax and potential changes.

CONCLUSION

As long argued in the literature and demonstrated in practice, the use of economic incentive mechanisms—both taxes and cap-and-trade—to achieve emissions outcomes can offer significant economic welfare improvements over less flexible approaches. Both mechanisms can be modified to more flexibly balance competing economic and environmental interests. Such balance may better achieve society's objectives as well as be helpful or necessary to reach agreement for policy enactment.

This Essay describes three possible adjustment mechanisms applicable to carbon taxes that might help steer actions toward achieving quantitative emissions goals: tax adjustments, regulatory tools, and revenue spending. Each has potential advantages and disadvantages, some of which are discussed here. Moreover, variants and combinations of each mechanism exist. In particular, it is possible to imagine an automatic adjustment,

[34] Framework Convention on Climate Change, Adoption of the Paris Agreement, U.N. DOC. FCCC/CP/2015/L.9/REV.1, art. 6 (Dec. 12, 2015), https://perma.cc/5ZRS-4NP3.

triggered when a particular emissions performance threshold is reached, or to imagine that such an intervention would be at the discretion of Congress or a delegated agency. As a compromise, policy could establish the prospect of periodic intervention with a clear timeline for Congress or a delegated agency to act before default automatic adjustments come into play.

The main purpose of this Essay is to explore options for incorporating emissions goals into a carbon tax. Consequently, it raises more questions than it answers. As discussions of a possible carbon tax evolve over time, research aimed at providing answers to these questions may be important for policy decisions and design.

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Working Paper 26629
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ABSTRACT

Pricing carbon emissions from a jurisdiction could harm the competitiveness of local firms, causing the leakage of emissions and economic activity to other regions. Past research concentrated on national carbon prices, but the impacts of subnational carbon prices could be more severe due to the openness of regional economies. Focusing on subnational carbon pricing in the United States, we specify a flexible model to capture competition between a plant in a state with carbon pricing and plants in other states or countries. We estimate model parameters using confidential plant-level data from 1982–2011 and simulate the effects of regional carbon prices covering the Northeast and Mid-Atlantic (regions that currently cap carbon emissions from the electric sector) on manufacturing output, employment, and profits. Importantly, we model industry mix within a state or region, not simply energy price differences. A carbon price of $10 per metric ton reduces employment in the regulated region by 2.7 percent, and raises employment in nearby states by 0.8 percent; the effects on output and profits are broadly similar. National employment falls just 0.1 percent, suggesting that domestic plants in other states as opposed to foreign facilities are the principal winners from state or regional carbon pricing.

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1. Introduction

Increasingly, carbon prices vary across jurisdictions that trade goods with one another. This phenomenon exists in the United States and the European Union, where most countries participate in the EU Emissions Trading System. Many individual nations also have policies that effectively cause carbon prices to differ from prices elsewhere in Europe and international prices. In the United States, several states are considering adopting a carbon price (either an emissions tax or cap) or strengthening existing carbon prices. Since 2009, the Northeast has capped carbon emissions from the electricity sector. And California has capped most state-wide carbon emissions since 2012. Other states are considering introducing a carbon price for electricity generation, transportation, and other sectors.[2] The abrupt change in US climate policy between the Obama and Trump administrations has likely contributed to states' growing interest in pricing carbon as a substitute for federal policy.

By design, pricing carbon emissions raises energy prices in accordance with the carbon content of the energy. The economic cost of the resulting price increases has been a contentious issue for states and regions considering carbon pricing because manufacturing plants located in jurisdictions with such policies are potentially put at a competitive disadvantage, which could reduce their output, employment, and profits. Moreover, reduced output in regions with carbon pricing may be offset by increased output elsewhere, resulting in emissions leakage—a situation in which net global emissions decline by less than emissions reduction in the carbon pricing region. Adverse competitiveness effects of a carbon price thus can lead to broader negative economic and environmental consequences.

A large body of literature examines the potential for international leakage—in which case a country (or set of countries) imposes a carbon price, causing emissions to flow to countries without carbon pricing policies. A central insight of this literature is that the extent of leakage

[2] For example, as of late 2018, Oregon was considering pricing carbon and linking its program with California's, and many states in the Mid-Atlantic and Northeast were also considering the expansion of the existing Regional Greenhouse Gas Initiative (RGGI) that covers electricity sector emissions.

depends on the degree of competition between firms in countries that impose a carbon price and those that do not.[3]

Given the trend in state-level US climate policy, we examine industrial sector leakage from states that adopt a carbon price. Applying the conclusions from the leakage literature to state-level carbon pricing suggests that the geographical shifts in economic activity from state or regional policies could be greater in magnitude than those from a national carbon price. Electricity accounts for less than 2 percent of total US manufacturing costs. However, for aluminum, chemicals, cement, and certain other industries the cost share is considerably higher—suggesting proportionately larger negative effects of higher electricity prices. Plants also combust fuels directly and consume electricity and fuels indirectly that are embodied in their production materials.

Moreover, states export a large share of their manufacturing output, making state-level manufacturing output sensitive to competition from other states and countries. In 2012, about 65 percent of manufacturing output (by value) was shipped more than 100 miles and about 65 percent of output was shipped to another state or country. The domestic competitive pressures faced by manufacturing plants in a particular state suggest that even a modest carbon price applied to only that state could be costly and lead to a substantial decrease in output and employment, as well as emissions leakage. In contrast, because a national carbon price would affect energy prices by similar amounts for all US plants, the effects on competitiveness of US plants would be relatively smaller as long as domestic competition is stronger than international competition.

State policymakers could take steps to reduce these adverse effects on competitiveness for the manufacturing sector. In particular, states could use tax revenue (or in the case of a cap-and-trade program, allocate emissions credits rather than auction them) to compensate firms and reduce the likelihood of employment and output losses and the risk of emissions leakage. For example, to reduce leakage from its cap-and-trade program, California allocates emissions credits to certain industries based on their energy intensity and exposure to international

[3] For example, see Fowlie, Reguant, and Ryan (2016); Fischer and Morgenstern (2009); Fischer and Fox (2012); and Boehringer, Fischer, and Rosendahl (2010).

competition. However, using the tax or auction revenue this way has an opportunity cost because that revenue could be used for other public purposes, such as infrastructure investments. Clearly, there are costs to over or undercompensating the manufacturing sector, and policymakers need to know the magnitude of the adverse competitiveness effects of state or regional carbon prices.

Despite the importance of these issues in US policy debates, the existing literature provides little insight into the effects of a state's carbon price on economic activity in the state and emissions leakage to other regions. The few existing studies focus on national carbon pricing. Using national-level data, Aldy and Pizer (2015) estimate the effects of energy prices on manufacturing employment. They use their results to infer the effects of a hypothetical national carbon price, finding that a carbon tax of $15 per ton would increase net imports by up to 0.8 percent for the most energy intensive industries. Because they use national-level data, their results reflect competition among US and international manufacturing plants. The effects of a statewide carbon price depend not only on US and international competition, but also on competition among states. Although Kahn and Mansur (2013) estimate the effect of electricity prices on employment by comparing adjacent counties, their analysis does not directly translate to a statewide carbon price, which would affect energy prices at the state and not the county level. The general equilibrium literature (e.g., Boehringer, Fischer, and Rosendahl 2010; Fischer and Fox 2012; and Adkins et al. 2012) lacks the geographic resolution necessary to address this question.

Building on our previous work (Gray, Linn, and Morgenstern 2016), we quantify the competitiveness effects of state-level carbon pricing. Specifically, we estimate the effects of a state or regional carbon price on manufacturing output, employment, and profits—both for those plants that face carbon prices and for other domestic plants not subject to carbon pricing. To accomplish this, we develop a general model linking a manufacturing plant's output, employment, and profit with the energy prices it faces as well as the prices faced by its competitors. We estimate the model parameters using confidential plant-level data from a 30-year panel, and use the model to consider particular examples of carbon pricing in the Northeast

and Mid-Atlantic under the assumption that the carbon price is passed through into energy prices faced by the plant.[4]

More specifically, the model links plant-level outcomes to energy prices, where the outcomes include employment, output, value added, and operating profits. We decompose the effect of a regional carbon price on a plant's outcome into two channels: a) the change of the national average outcome for the corresponding industry; and b) the deviation in the plant's outcome from that national average outcome. We estimate the first channel using an approach similar to Aldy and Pizer (2015).

Estimating the second channel is the primary literature contribution of our empirical analysis. This empirical component contains several features that make it particularly suitable for the analysis of state-level carbon pricing. First, and most importantly, we control separately for the energy prices a plant faces and the energy prices faced by competing plants in other states and countries. This allows us to show transparently how carbon pricing in one state affects outcomes in that state and others. Second, we allow the effects of energy prices on output and employment to vary across industries and in a flexible manner. We partially relax assumptions that many other studies (e.g., Linn 2008, 2009; and Aldy and Pizer 2015) have imposed on the relationships between a plant's energy cost share and the elasticity of its output and employment to energy prices. Third, because some states (e.g., California) price carbon emissions from electricity and fuels whereas other states (e.g., New York) price carbon only for electricity, the model includes separate measures of electricity and fuels prices. In contrast, some empirical studies, such as Aldy and Pizer (2015), aggregate electricity and fuels. Finally, the model accounts for the energy embedded in materials inputs and also for demand and labor cost shocks. This model extends the work of Gray, Linn, and Morgenstern (2016) in several ways: including all industries rather than selected energy-intensive, trade-exposed industries in the analysis; including all fuels rather than just natural gas; and controlling for indirect energy use. These advances make it possible to evaluate a wide range of actual or hypothetical state carbon prices.

[4] Ganapati, Shapiro, and Walker (2017) estimate the pass-through of energy prices to marginal costs and output prices. Our assumption on pass-through regards the pass-through of the carbon price to energy prices, and not output prices for the manufacturing plants. Fabra and Reguant (2014), among others, provide evidence on full pass-through of a carbon price to energy prices.

We use plant-level Census data from 1982–2011 to estimate a short-run (annual) reduced-form model of energy prices and the economic outcomes of interest (employment, output, value added, and operating profits). The parameter estimates largely conform to intuition. The effects of a plant's own energy prices on its output, employment, and profits are generally negative—reflecting the decrease in competitiveness for a plant that faces higher energy prices, all else equal. The effects of competing plants' energy prices are typically positive for the same reason, because an increase in a competitor's energy prices is advantageous to other plants. Energy-intensive industries are typically more adversely affected by energy prices than other industries.

The model is quite general and could be applied to consider any state or regional carbon price in the United States. As an application, we use the model to simulate the effects of carbon prices in the Northeast and Mid-Atlantic. We focus on these regions for two main reasons. First, the Regional Greenhouse Gas Initiative (RGGI) has capped carbon emissions from the electricity sector in the Northeast since 2009. New England and much of the Mid-Atlantic currently belong to RGGI.[5] Carbon prices have typically been low, at around $2 per ton of carbon dioxide (CO_2), but recent changes to the program may cause emissions prices to increase substantially in the coming years.[6] Second, several states have considered joining RGGI, and political opposition has pointed to the potential adverse effects on manufacturing.

We define two carbon price scenarios, relative to a no-policy baseline. The first scenario includes a carbon price of $10 per ton of CO_2 for the current RGGI states. The second scenario assumes that Pennsylvania and New Jersey join the program, and we compare this scenario against the first scenario. We chose these states because they border the RGGI region and have previously belonged to RGGI or have considered joining; both states have substantial levels of manufacturing employment. We also consider higher carbon prices and carbon prices that affect electricity and fuels. The additional scenarios are motivated by the fact that some RGGI states have considered expanding their carbon price to include fuels used by the manufacturing sector.

[5] More specifically, RGGI includes Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey initially participated but dropped out in 2012.
[6] In 2017, RGGI states adopted an emissions containment reserve. If the emissions price falls below specific target levels, participating states may withhold allowances from circulation, which would put upward pressure on the allowance price.

Given the estimation results, we expect several patterns to emerge in the simulations. First, the RGGI carbon price on electricity should reduce manufacturing employment, output, and profits in RGGI states, and increase these outcomes in neighboring states. Second, these effects should be larger in magnitude for energy-intensive industries than for other industries. Third, expanding RGGI should reduce employment, output, and profits in the states that join RGGI, and increase those outcomes in states close to the expanded RGGI region in our analysis.

Our results confirm these expectations. Specifically, a RGGI carbon price of $10 per ton of CO_2 reduces employment by 2.7 percent in RGGI states. The carbon price has similar effects on output and profits. A RGGI carbon price increases employment, output, and profits in neighboring states by 0.8 percent on average, suggesting a substantial shift of economic activity outside of RGGI. National employment falls by just 0.1 percent, suggesting that most of the adverse economic effects on the RGGI states occur due to domestic rather than international competition. Expanding the carbon price to include additional states reduces the employment, output, and profit losses for the original RGGI states. This suggests that adverse economic effects and leakage within the United States are highly sensitive to the geographic extent of the carbon price.

2. Empirical Strategy

2.1 Decomposing the Effects of a Regional Carbon Price

The objective of the empirical model is to characterize the reduced-form relationship between energy prices and various plant-level outcomes: value of shipments; value added (defined as the difference between the value of shipments and the sum of energy and materials costs); employment; and operating profits (defined as the difference between the value of shipments and the sum of energy, materials, and labor costs).

As noted in the introduction, Aldy and Pizer (2015) estimate the effects of national average energy prices on national employment, and they use the results to make inferences on the effects of a hypothetical national carbon price on national employment. One expects that a national carbon price would affect employment in a given industry in the same direction across all regions of the country, although the magnitude of the effect could vary across regions due to regional differences in energy intensity or other factors. In our context, by contrast, a regional

carbon price would not have such uniform effects. A carbon price in the Northeast, for example, could reduce employment in the Northeast but increase employment in other regions. The effects of regional carbon prices are more likely to vary in direction across regions with a greater degree of competition among plants across regions.

This possibility suggests decomposing into two terms the effects of a regional carbon price on the outcomes of plant i in industry j. The first term is the effect of the regional carbon price on the national average of that outcome for the industry, Δy_j. This term captures competition among domestic and foreign plants in the industry. If plants in the industry compete closely with foreign plants, the national average effect should be negative—but if competition is purely domestic, the national average effect could be zero.

The second term in the decomposition is the plant's deviation from the corresponding national average, Δy_{ij}. This term captures domestic competition. If the region imposes a carbon price, the deviation should be negative, as the carbon price causes plants in the region to be less competitive compared to other domestic plants. If the region does not impose a carbon price, the deviation should be positive because the plants in the region are more competitive compared to plants in the regulated region.

Aldy and Pizer (2015) estimate the first term in this decomposition. Identifying the second term is the main focus of our empirical analysis, as discussed below.

2.2 Estimating Deviations from National Average Effects

This subsection describes the short-run econometric model that links a manufacturing plant's economic activity to the energy prices it faces and the energy prices of its competitors. The effects of energy prices on an individual manufacturing plant depend on where the plant is located. For example, suppose Massachusetts adopts a carbon price that raises energy prices, and that no other states adopt a carbon price. In that case, the energy costs of plants located in Massachusetts increase relative to competing plants elsewhere. In contrast, for a plant located outside the Bay State, the energy prices it faces do not change, while the prices paid by its competitors increase. The increase in energy prices in Massachusetts, therefore, can create a competitive advantage for plants located outside the state.

For either a plant in Massachusetts or a plant outside the state, we can express output, employment, value added, or profits (y) as a function of the energy prices faced by either plant and the energy prices of its competitors:

$$\ln(y) = \beta_1 s * \ln(p) + \beta_2 s * \ln(p_R) \quad (1)$$

where s is the cost share of energy, p is the energy price the plant faces, and p_R is the energy price faced by plants in other states. The energy cost share is multiplied by the energy price because a given energy price increase should have a greater effect on the outcomes for energy-intensive industries than for other industries. We expect β_1 to be negative because a plant facing higher costs should produce less output and have lower profits, and these negative effects should increase in magnitude with the cost share. In principle, if energy and labor are strong enough substitutes, the coefficient could be positive for employment.

In the case where output is on the left-hand side of Equation (1), this particular functional form (in which we interact the cost shares with the energy prices) represents a generalization of a Cobb-Douglas production function. If the plant has a Cobb-Douglas production function, the output would be directly proportional to the interaction of the cost share with the price, and β_1 would equal –1.

The parameter β_2 should be positive because an increase in the energy prices of competing plants makes the plant more competitive relative to those plants. For example, a Massachusetts energy price increase would increase the competitiveness of plants outside the state that compete with Massachusetts plants, causing their y to increase. Note that we could express the outcome variable as a function of the price of energy faced by the Massachusetts plant relative to the price of energy in other states (i.e., p / p_R), which would be equivalent to setting $\beta_1 = -\beta_2$ in Equation (1).

To arrive at the estimating equation, we relax a number of assumptions embedded in Equation (1). First, Equation (1) includes aggregate energy prices but the specific policies we consider affect electricity and natural gas prices in different ways. Consequently, we distinguish

between the consumption of electricity and the consumption of fuels, which primarily include natural gas and petroleum products for the manufacturing industries studied here.

Second, Equation (1) includes the assumption that energy prices affect economic activity in proportion to the cost share of energy. Aldy and Pizer (2015) and others in the literature make a similar assumption, but given the available data we can partly relax this assumption. We define eight industry groups based on their energy cost shares and we allow the coefficient on their cost shares to vary across groups. For industries belonging to the same group, energy prices affect economic activity in proportion to the energy cost shares, but we do not assume any proportionality across groups. This approach allows the data to determine whether energy prices have larger effects for high-consuming groups than for other groups, and allows for non-loglinear relationships among energy prices and outcomes.

Third, we account for indirect energy use. In the short run, with the capital stock fixed, plants select inputs of energy, labor, and materials. Linn (2009) shows that energy prices can affect economic activity directly, by raising the energy costs faced by a plant, as well as indirectly, by affecting the prices of materials inputs. Ganapati, Shapiro, and Walker (2017) show that energy prices affect marginal costs and output prices for certain industries, providing further evidence that energy prices can affect a plant indirectly via intermediate materials prices. Consistent with these studies, we assume that the indirect effect depends on the energy intensity of the inputs a plant uses. For example, an increase in crude oil prices causes prices of petroleum products to increase, which affects production costs more for plants that use petroleum products than for those that do not. As described below, we use input-output relationships between industries to compute the average electricity and fuels cost shares of the materials each plant consumes. We interact the electricity and fuels cost share variables with their corresponding prices.

Fourth, we control for the plant's labor costs. We allow the coefficient on labor costs to differ across the energy cost share groups. Further, we recognize that energy prices may be correlated with product demand. Energy price increases often accompany or precede macroeconomic downturns, which would bias estimates of the effects of energy prices on economic activity. We control flexibly for national industry-level demand shocks by including interactions of industry- and year-fixed effects. We take two approaches to control for subnational demand shocks. Using

an approach that builds on Ellison and Glaeser (1999), we control for product demand of an individual plant based on input-output relationships between industries as well as a plant's proximity to demanding industries. In addition, we include interactions of fixed effects for Census region and year to allow for regional demand shocks. These interactions control for regional changes in input costs, regional product demand shocks, as well as international supply and demand shocks that affect each industry proportionately. The next section describes the construction of these variables in detail.

After making these modifications to Equation (1), we arrive at the estimating equation:

$$\begin{aligned}\ln(y_{ijt}) = \beta_0 + \beta_1^E s_j^E \ln(p_{ijt}^E) + \beta_2^E s_j^E \ln(p_{R,ijt}^E) + \beta_1^F s_j^F \ln(p_{ijt}^F) + \beta_2^F s_j^F \ln(p_{R,ijt}^F) + \delta_1^E m_j^E \ln(p_{ijt}^E) \\ + \delta_2^E m_j^E \ln(p_{R,ijt}^E) + \delta_1^F m_j^F \ln(p_{ijt}^F) + \delta_2^F m_j^F \ln(p_{R,ijt}^F) + \gamma_1^E \ln(p_{ijt}^E) + \gamma_2^E \ln(p_{R,ijt}^E) \\ + \gamma_1^F \ln(p_{ijt}^F) + \gamma_2^F \ln(p_{R,ijt}^F) + \mu_1 LCOST_{ijt} + \mu_2 DGROWTH_{ijt} + \delta_{rt} + \delta_{jt} + \varepsilon_{ijt}\end{aligned} \tag{2}$$

where the dependent variable is employment, output, value added, or gross operating profits by plant *i* in industry *j* and year *t*. Equation (2) includes interactions of the log of the plant's electricity price (p_{ijt}^E) with the industry's electricity cost share (s_j^E), as well as the interaction of the log of the electricity price of competing plants $(p_{R,ijt}^E)$ with the cost share. The equation includes corresponding terms for fuel prices, where the superscript *F* indicates a fuels price index rather than electricity (*E*). The second line in the equation includes the interactions of the energy price variables with the indirect energy use shares (m_j^E and m_j^F). The variables are average electricity or fuels cost shares of the industry's materials. The equation includes the principal effects of electricity and fuels prices, with these effects being absorbed by the corresponding industry-year interactions (δ_{jt}). The variables $LCOST_{ijt}$ and $DGROWTH_{ijt}$ indicate labor costs and demand growth; δ_{rt} are region–year interactions; and ε_{ijt} is an error term. The next subsection describes the definitions of the competing energy prices, as well as the construction of the measures for indirect energy use, labor costs, and demand growth.

We estimate Equation (2) separately for each energy cost share group, omitting group subscripts in the equation to simplify the notation. Because we perform a separate estimation for each group, we allow for cross-group heterogeneity in the effects on economic activity of electricity prices, fuels prices, indirect energy use, labor costs, and demand growth.

The industry-year interactions play an important role in the identification and interpretation of the coefficients on the variables that include energy prices. These interactions control for the effects of energy prices on the average of the outcome for each industry and year. Consequently, the coefficients are identified by deviations from industry-year means of energy prices interacted with cost shares. For this reason, the coefficients capture precisely the second term in the decomposition introduced in the previous subsection—that is, the deviations from the national averages of the effects of energy prices on a plant's outcomes.

Based on the intuition from Equation (1), within a cost share group, we expect that a plant's electricity and fuels prices negatively affect the outcomes, and that the negative effects are larger in magnitude for plants with higher cost shares—that is, the interaction terms for the plant's energy prices are negative. Likewise, we expect positive coefficients for the interaction terms involving energy prices of competing plants. We expect the signs on the indirect energy use interactions to be the same as the signs of the corresponding direct energy use interactions.

2.3 Estimating National Average Effects

Equation (2) identifies a plant's deviations from national industry average effects of energy prices. To estimate the total effect of a carbon price, we therefore need to estimate the effects of energy prices on national averages of the four outcomes. To accomplish this, we take an approach similar to that of Aldy and Pizer (2015) and estimate an industry-level regression

$$\ln(y_{jt}) = \theta_0 + \theta_1^E c_j^E \ln(p_t^E) + \theta_1^F c_j^F \ln(p_t^F) + \rho_1 LCOST_{jt} + \rho_2 DGROWTH_{jt} + \tau_t + \tau_j + \varepsilon_{jt} \quad (3)$$

where the dependent variable is employment, output, value added, or gross operating profits by industry *j* and year *t*. The equation includes the interaction of the industry's electricity or fuels cost share with the log of the average price of electricity or fuels in year *t*. Because there is less price variation in the aggregate than in the plant-level data, we add the direct and indirect cost shares in Equation (2) to create a combined cost share, *c*, in Equation (3). The variables for labor costs and demand growth are defined similarly to Equation (2), except that they are aggregated across plants. The equation includes year and industry fixed effects, and an error term.

The coefficients on the cost share–energy price interactions are the key coefficients of interest. They are identified by time series variation in energy prices interacting with cross-industry variation in cost shares. For example, if the price of electricity increases between one year and the next, the interaction coefficient is identified by cross-industry variation in the response of the dependent variable to the price increase. One expects an electricity price increase to have a larger negative effect for industries that consume more electricity than others (either directly or indirectly via intermediate materials), in which case the interaction coefficient is negative. Note that the equation omits the main effects of the cost shares and energy prices because they are absorbed by the industry and year fixed effects. The year fixed effects control for average energy prices in other countries and any other global demand or supply shocks that affect all industries proportionately. Therefore, the energy price coefficient captures the effects of domestic energy prices, holding international prices fixed. This is an important aspect of the estimation because the simulations implicitly hold international prices fixed. The labor cost and demand growth variables account for supply and demand shocks that vary across industries.

Although Equation (3) is broadly similar to Aldy and Pizer (2015), there are a few important differences. First, and most importantly, we estimate separate effects for electricity and fuels prices. This is consistent with Equation (2), and enables us to simulate carbon prices that affect electricity prices only, as well as carbon prices that affect both electricity and fuels prices. Second, we include only industry and year fixed effects rather than interactions of year fixed effects with aggregated industry fixed effects. Including only the year fixed effects rather than additional controls is for consistency with the simulations discussed below. Third, we use aggregate energy prices rather than industry-specific energy prices to reduce concerns about endogeneity. Fourth, we account for both direct and indirect energy use, which is consistent with the empirical analysis cited above as well as the plant-level estimation in Equation (2), and allows for the possibility of indirect effects of energy prices acting through intermediate materials prices. Finally, we omit controls for oil prices, physical capital, and human capital. These choices are motivated primarily by parsimony to focus on the key coefficients of interest. In practice, these differences do not appear to substantially affect the results; we obtain similar estimates to those reported in Section 4 if we use a specification more similar to Aldy and Pizer (2015).

3. Data and Summary Statistics

Our analysis is based on confidential plant-level data collected by the Census Bureau in the Census of Manufactures (CMF) and the Annual Survey of Manufactures (ASM), which provide data on output, revenue, employment, and expenditures. The CMF is conducted every five years and includes data from all manufacturing plants; we use all years of the CMF from 1982–2007. The ASM samples small plants and includes all large plants; we use the ASM data from 1983–2011. The ASM and CMF records are linked together over time in the Longitudinal Business Database, as described in Jarmin and Miranda (2002). Our final dataset includes about 2.5 million plant-year observations, covering all manufacturing industries except those that shifted in or out of the manufacturing sector during the 1997 switch from the Standard Industry Classification (SIC) to the North American Industry Classification System (NAICS) industry definitions.

Four measures of economic activity in the ASM/CMF data provide the dependent variables for our analysis: employment, output, value added, and profits. Employment is measured as the plant's total employment including both production and nonproduction workers. Output is measured as the plant's total value of shipments. Value added is measured in the ASM/CMF by taking the value of shipments and subtracting the combined costs of materials, supplies, containers, fuels, purchased electricity, and contract work, adjusting for inventory changes.[7] Profit is measured by gross operating profits, obtained by subtracting labor costs from value added. Output, value added, and profits are all deflated by the industry's price deflator for shipments from the NBER-CES Manufacturing Industry Database.[8]

Our key explanatory variables are related to energy costs. The ASM/CMF data provide annual plant-level expenditures separately for electricity and fuels and also provide the quantity of electricity purchased. We calculate average (rather than marginal) plant-level electricity prices as the ratio of electricity expenditure to the quantity of purchased electricity. Using the 1992 CMF, we calculate the average share of electricity or fuels in the value of shipments by industry. Under the standard assumption that plants earn zero economic profits in the long run, these shares equal the corresponding cost shares.

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[7] https://www.census.gov/glossary/#term_Valueadded.
[8] https://www.nber.org/data/nberces.html.

Because the ASM/CMF data do not include quantities of purchased fuels throughout the sample, we use state-level industrial prices for five fuels (coal, natural gas, distillate fuel oil, residual fuel oil, and liquefied natural gas) from the US Energy Information Administration. The computed fuels price varies by industry, state, and year and equals the weighted average price across the five fuels using expenditure shares as weights from the 1981 ASM.

We use geocoded Census data from the Longitudinal Business Database to approximate cross-state competition among plants. First, we randomly select 10,000 ASM/CMF plant observations from each state. If at least 1,000 of the businesses in one state are located within 500 miles of 1,000 businesses in another state, those two states are deemed to be neighbors. We calculate neighbor electricity and fuels prices for each plant in our sample as the average of the electricity and fuels prices across all plants in the same industry in neighboring states. These neighbor prices vary by industry, state, and year, and they account for geographic concentration of plants within a state.

The labor cost index is computed from the labor cost for plants in the same industry and state, as well as plants in the same industry in neighboring states. The index is the total payroll for all such plants divided by their total employment, using the 500-mile definition to define the set of neighboring plants and excluding the plant's own payroll and employment.

The demand growth index varies by plant and year and is based on downstream economic activity and shipping patterns. First, input-output (IO) tables from the US Bureau of Economic Analysis (BEA) identify for every "making" industry how much of its output is purchased by each "using" industry. We use both the 1992[9] (SIC-based) and 2007[10] (NAICS-based) IO tables, and use concordances between the BEA industry codes and the SIC/NAICS industry codes to link the IO tables to each of our plants in each year, identifying which other industries (both manufacturing and nonmanufacturing industries, including final demand) purchase that plant's products. Second, the 2002 Commodity Flow Survey (CFS) identifies the distances traveled by shipments from plants in each industry, reported by three-digit NAICS industry of the shipped products.[11] For each three-digit NAICS industry, we compute the share of shipments traveling less than 250 miles, the share of shipments traveling between 250 and 1,000 miles, and the share of shipments traveling more than 1,000 miles. Third, annual state-level industry output data from

[9] http://www.bea.gov/industry/io_benchmark.htm.
[10] http://www.bea.gov/industry/io_annual.htm.
[11] http://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/commodity_flow_survey/index.html.

BEA identifies the activity level of different "using" industries around the country, with final demand proxied by personal income in the state.[12]

For each plant in our dataset and for each industry that uses the products of that plant, we calculate the amount of that industry's production that is located in states within 250 miles of the plant (including the plant's own state), between 250 and 1,000 miles from the plant, or more than 1,000 miles from the plant. We then use the IO data to predict the demand for the plant's products, aggregated over all these "using" industries, at each of the three distances. We calculate the annual growth rate in product demand at each distance and weight those three growth rates using the CFS weights for the share of the plant's shipments expected to travel those distances, yielding a weighted projected demand growth. Finally, we transform these growth rates into an index number by assigning them all a value of 150 in 1987.[13]

We allow for differences among groups of industries in our estimation models, based on the energy intensity as measured by the industry's total expenditure on electricity and fuels divided by its total shipments. We split the industries into 8 separate groups, with greater detail provided among industries with higher energy intensity. Group 1 includes half of the 6-digit NAICS industries, with each of Groups 2–4 including 10 percent each and each of Groups 5–8 including 5 percent. Table 1 shows some key information for each group, such as the share of the sample and the energy cost shares. Plants in more energy intensive (higher-numbered) groups tend to have higher expenditures on both electricity and fuels but otherwise don't differ much in their average employment, shipments, value-added, or operating profits.

We define high-energy industries as those belonging to Groups 5–8, which collectively include the top quintile of energy-intensive industries. Figure 1 shows the variation over our time period in average energy prices and cost shares as well as output and employment for the entire manufacturing sector and for high-energy manufacturing industries. The cost share of high-energy industries declined by half over the period (from about 6 to 3 percent), and energy cost shares declined by about one-third in the manufacturing sector as a whole (from about 3 to 2 percent). In contrast, energy prices followed similar trends for high-energy industries and all industries. Output growth was noticeably slower for high-energy industries as compared to others, while the decline in employment over the period was similar in both groups. Figure 2 shows geographic variation of electricity and fuels prices. Among RGGI or potential RGGI states, New Hampshire, Connecticut, and Massachusetts have the highest electricity prices; Vermont and New Jersey have the highest fuels prices.

[12] http://www.bea.gov/regional/index.htm.

[13] The starting value of 150 in 1987 was chosen so that the demand index numbers would remain positive throughout the sample for all industries.

4. Estimation Results

4.1 Deviations from National Average Effects

Equation (2) includes multiple coefficients on energy prices and energy price interaction terms. There are separate terms for electricity and fuels prices; interactions of those prices with corresponding cost shares; prices for competing plants and interaction terms; as well as for direct and indirect energy use; and a separate set of coefficients for each of the 8 groups, for a total of 96 energy-related coefficients. Because of this large number of coefficients, we focus on the overall elasticities with respect to energy prices, which include both the direct effect of energy purchased by the plant and the indirect effect via the energy-intensity of its purchased materials.[14]

Figure 3 plots the elasticities for employment and output by group for electricity prices, and Figure 4 provides the analogous information for fuels prices. The figures illustrate separately the elasticities with respect to the plant's own energy prices as well as the energy prices of competing plants in neighboring states. The figures show the elasticities and confidence intervals for each group. (The underlying regressions were estimated with clustering by industry-year.)

The own electricity price elasticities in Figure 3 (panels A and B) are typically negative and increase in magnitude, moving from the low cost-share groups to the high cost-share groups. The increase is not perfectly monotonic, and there are deviations for Group 6 (employment) and Group 7 (output). The mean employment elasticities range from -0.07 to -0.90 across the 8 groups, while the output elasticities range from -0.07 to -1.19, with all of them statistically significant at the 5-percent level. The fact that there are a few positive elasticities is perhaps not surprising, given the flexible functional form of Equation (2) and the large number of estimated coefficients (that is, one would expect that by chance there would be a few positive and statistically significant coefficients).

The own fuels price elasticities in Figure 4 (panels A and B) are also typically negative (3 of 16 are positive but only one of those is significant, while 12 of the 13 negative elasticities are significant), but they are smaller and less precisely estimated than the electricity elasticities. The

[14] The full set of coefficients are available from the authors.

relationships between the cost shares and the elasticities of the groups are weaker than for electricity. The significant negative elasticities range from -0.08 to -0.29 for employment and from -0.10 to -0.32 for output across the 8 groups.

Overall, for most industry groups the own-electricity elasticities are negative and the magnitudes increase with the cost share. The neighbor elasticities tend to be positive but there is not a correlation between the magnitude of the elasticities and the cost share. Own-fuel elasticities tend to be negative and neighbor-fuel elasticities tend to be positive, although there are a few exceptions to these patterns.

These elasticities are similar to those found in Gray, Linn, and Morgenstern (2016), in which we applied a similar model to plant-level data for 49 energy-intensive, trade-exposed industries and found average elasticities with respect to electricity prices of -0.6 for employment and -0.8 for output. Two other papers in the literature estimate own-price elasticities but not neighbor elasticities. Aldy and Pizer (2015) find a somewhat lower elasticity of output with respect to energy prices of -0.4, using national-level industry data from 1986–1994. Kahn and Mansur (2013) use County Business Patterns data and report estimates similar to ours, finding an elasticity of output with respect to electricity prices ranging from -0.2 for their average industry to -2.2 for their most electricity-intensive industry (primary metals).

The elasticities for competitors' energy prices, seen in panels C and D of Figures 3 and 4, are typically positive for both electricity and fuels. As with the own-energy price elasticities, the elasticities with respect to neighbors' electricity prices are larger in magnitude and more precisely estimated than those for fuels. This difference between electricity and fuels elasticities is similar to that reported in Gray, Linn, and Morgenstern (2016) for electricity and natural gas, and likely reflects the lesser variation across states in prices for fuels. Across the 8 groups, the majority of the elasticities with respect to neighbors' energy prices have the expected positive sign and are statistically different from zero.

4.2 National Average Effects

Table 2 reports the estimates of Equation (3), for which we regress the variable indicated in the column heading on electricity and fuels prices interacted with cost shares. Recall that the energy price variables include both the direct and indirect effects. For each dependent variable,

the coefficient estimates are negative, which is as expected and consistent with the literature. Unfortunately, we do not have sufficient variation to precisely estimate the electricity coefficients. The fuel coefficients are estimated at the 5-percent confidence level or better.

5. State Carbon Prices and Competitiveness

5.1 Main Scenarios

The objective of the simulations is to illustrate the effects of state carbon pricing on competitiveness. In this subsection we define the two main scenarios that we analyze in comparison to a no-policy baseline scenario.

The baseline scenario uses the observed energy prices and other independent variables across the entire estimation sample. We use Equation (3) to predict national average outcomes for each industry and Equation (2) to predict deviations from the national averages. By construction, the predicted values are equal to the observed sample means.

To compare with the baseline, in the first policy scenario we add a carbon price of $10 per ton of CO_2 that raises electricity prices in the RGGI region, which includes Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. For simplicity, we assume that the carbon price raises electricity prices in proportion to the emissions rate of a natural gas–fired unit. Consequently, electricity prices increase by 0.6 cents per kilowatt hour in the RGGI states.[15] We also assume that the carbon price does not affect electricity prices in other states or fuels prices in any states. Consequently, for plants in RGGI, their own electricity prices rise and the electricity prices of competing plants are unchanged. For plants close to RGGI, their own electricity prices are unchanged and the electricity prices of competing plants rise.[16]

[15] The effect of the carbon price on electricity prices is broadly consistent with estimates reported in Linn and Muehlenbachs (2018), who estimate the effect of fuels prices on wholesale electricity prices using data from the 2000s.

[16] In principle, a carbon price in RGGI could affect electricity prices outside the region. The carbon price raises the cost of producing electricity in RGGI, which could increase generation from outside the region, causing marginal costs and electricity prices to increase. Shawhan et al. (2014) suggest that for a carbon price of $10 per ton of CO_2, this effect would be small compared to the increase in electricity prices in the RGGI region. For simplicity, the simulations do not include this effect.

Equation (2) and these counterfactual plant-level electricity prices are used to predict deviations from national averages of employment, output, and profits. Then, we use Equation (3) to predict national average changes for each industry. The price increases for RGGI and the share of RGGI plants in national employment are used to compute the change in national average electricity prices. Because RGGI plants account for about 10 percent of national employment on average across all industries, national average electricity prices increase by about 2 percent for the average industry. We combine the results of Equations (2) and (3) for each plant in the data-set, and then compute percent changes in the outcomes for each plant, relative to the no-policy baseline.

Based on the estimation results reported in the previous section, we expect the RGGI carbon price to reduce employment, output, and profits in RGGI states and increase those outcomes in surrounding states. The total effect across the entire country should be negative, because national average electricity prices increase. Because the plant-level elasticities (in Equation 2) tend to be larger in magnitude than the industry-level elasticities (in Equation 3), we expect the carbon price to induce shifts of employment, output, and profits to unregulated states.

The second carbon price scenario expands the RGGI carbon price to New Jersey and Pennsylvania. The plant-level outcomes are computed similarly to the first scenario. Relative to the no-policy scenario, we expect lower employment, output, and profits in the expanded RGGI region. Relative to the original RGGI scenario, we expect less of a reduction in employment, output, and profits since the average electricity prices of competing plants increase by less in the expanded RGGI scenario than in the original RGGI scenario.

5.2 Main Results

The main results are presented in a series of maps that illustrate the changes relative to the baseline scenario, showing state-specific effects on employment and output for the eastern half of the country, which includes all states that are neighbors of RGGI. In addition to the maps, Table 3 shows the average effects of each scenario for various groups of states, including the effects on profits as well as employment and output.

The results of the simulations generally follow the expected pattern, with reductions in employment, output, and profits in the RGGI states and increases in neighboring states. The

effects tend to be larger for RGGI states such as New York, Maryland, and Delaware that are located closer to non-RGGI states. The output effects tend to be larger than the employment effects, which is consistent with the elasticities seen in Figures 3 and 4. In Table 3 for the first scenario, the RGGI carbon price reduces average manufacturing employment in those states by 2.7 percent, and raises average employment in New Jersey and Pennsylvania by 0.8 percent (the increases are smaller in other eastern states). However, the maps show some variation in effects that are uncorrelated with the distance from RGGI states. For example, Figure 5 shows larger output changes for Kentucky and Tennessee than for some other states that are closer to RGGI. These variations could arise because of the specific mix of industries operating in RGGI and non-RGGI states, since relative energy prices only matter if there are competing plants in neighboring states to take advantage of the energy price differential. Thus, in Figure 5C we see larger output effects for Kentucky and Tennessee than for some other states that are closer to more RGGI states.

The effects of the carbon price on the high-energy industries are generally larger than for the average industry, as expected. The average employment in those industries falls by 7.1 percent in the RGGI states and output falls by 10.5 percent. The increases in employment and output in neighboring non-RGGI states are also larger than for the average industry, although still only about 0.5 percent. These larger effects make it easier to identify differences across particular states, including the variation across states within the regions shown in Table 3, which again shows Kentucky and Tennessee with larger output effects than those found for some other states closer to RGGI.

The results for the second scenario, where Pennsylvania and New Jersey join RGGI and adopt carbon prices, are as expected. The results are shown in Table 3 and Figure 6. Because of their location, those states now form a buffer between some of the original RGGI states and the neighboring non-RGGI states, and the effects on their employment and output are somewhat smaller on average than they were in the first scenario. The average across industries is a decline of 2.2 percent in employment and 3.4 percent in output, with similar reductions for the high-energy industries. The average declines in employment and output for Pennsylvania and New Jersey are larger than those for the original states, with a 3.3 percent decline in average employment and a 4.9 percent decline in average output across all industries. The estimated

effects on high-energy industries are also larger than those in the original RGGI states. The increases in the non-RGGI states are also larger than they were in the first scenario, reflecting the greater number of neighboring states with carbon prices. Table 3 also shows the predicted effect on operating profits, which is slightly larger than the effects on output, ranging up to a decrease of 11.2 percent for the high-energy industries in RGGI states.

5.3 Other Results

In this subsection we discuss the results of two variations in our scenarios. First, we redefine the RGGI and expanded RGGI scenarios so that the carbon price affects both electricity and fuels prices, rather than just electricity prices. This scenario corresponds to a situation in which the RGGI states decide to expand their programs to include fuels directly combusted (a California-style approach). The effects of this scenario are shown in Table 3 and Figure 7. Compared to the electricity-only scenario, the differences are due largely to the mix of specific industries operating in each state. Arguably, we might have expected to see larger effects, given the wider range of energy sources affected by the carbon price—but the average reductions in employment and output in the RGGI states are not much different from those in the first scenario. This may reflect the presence of a few unexpected signs for the own and neighbors' employment elasticities with respect to fuels prices. Figures 7A and 7B show employment reductions that are more concentrated in New York and Maryland than in the first scenario (Figure 4), and employment gains that are more concentrated in Pennsylvania and New Jersey.

Second, we set the carbon price to equal $25 per ton rather than $10 per ton in the RGGI electricity scenario, representing a tightening of the RGGI emissions caps. Figures 7C and 7D show the effect on employment for this scenario. The patterns across specific states are similar to those seen in the second scenario, but it's important to note that the scale of the map's colors needed to expand to reflect the larger effects seen here, with increases going up to 4 percent rather than 2 percent and reductions going down to 25 percent rather than 15 percent.

6. Conclusions

A substantial literature has analyzed empirically and theoretically the potential for international emissions leakage, in which a country or set of countries impose a carbon price that raises emissions in other countries. Accompanying the emissions leakage would be

corresponding shifts of employment, output, and profits to firms located in unregulated countries, representing the adverse competitiveness effects of the carbon price.

In the United States, certain states have adopted or are considering adopting a carbon price. The high degree of trade of manufactured goods across state lines raises the possibility of a substantial amount of leakage of economic activity across states. In the state-level policy context, leakage would be concerning not only because it would undermine the climate objectives of a carbon pricing policy but also because it would imply losses of local jobs and production. As policies evolve in this area, it is important to understand the magnitudes of potential leakage under state-level carbon pricing policies.

Clearly, it is not simply a matter of energy or carbon price differences across jurisdictions—the industry mix in different areas is also a major factor. Carbon pricing by a jurisdiction that has a monopoly or near monopoly on particular production capabilities would likely result in minimal competitiveness effects in that jurisdiction. Thus, to estimate the employment, output, or profit sensitivity of a particular jurisdiction requires consideration of multiple state- and region-specific factors of the type included in our modeling.

We decompose the effects of a carbon price on three plant-level outcomes (employment, output, and profits) into two effects: the change in the national average level of that outcome for all plants in the corresponding industry, and the individual plant's outcome deviation from the national industry average. The first part is estimated via similar methods as Aldy and Pizer (2015). We use a novel model and unique data to estimate the second part. Specifically, we link a plant's outcome deviations to the energy prices it faces as well as the energy prices of competing plants. This model thereby captures differing effects of the carbon price across plants in the same industry. For plants in the regulated region, the carbon price raises energy prices, making them less competitive, while plants outside the regulated region become more competitive. The model is further distinguished by separating the effects of electricity and fuels, and by allowing for indirect effects of energy prices to affect a plant via the prices of the energy-intensive materials that it uses in its production process.

The model parameters are estimated with confidential plant-level data from the Census Bureau from 1982–2011. As expected, higher energy prices at a plant typically reduce its

employment, output, and profits, with the magnitude of the effects generally increasing with energy intensity. Higher energy prices at competing plants tend to increase a plant's employment, output, and profits.

We then use the estimated parameters from the model to simulate the effects of regional carbon prices. We focus on the RGGI program, which prices carbon emissions from the electricity sector in the Northeast. A carbon price of $10 per ton reduces employment by 2.7 percent in the RGGI region, with comparable changes in output and profits. The same carbon price raises those outcomes in the surrounding states, with a 0.8 percent increase in employment. The national-level outcomes are relatively small, with employment declining by 0.1 percent, confirming that a substantial amount of the shift of output, employment, and profits flowing out of RGGI leaks into surrounding states rather than to other countries. We also show that expanding RGGI to include New Jersey and Pennsylvania would reduce the adverse competitiveness effects within the original RGGI region.

These results imply that state policymakers can reduce the degree of leakage—and the associated environmental and economic costs—by expanding their programs to include other states. The benefits of linking programs across states can be substantial, due to the fact that states' economies are so intertwined with such a high degree of cross-state trade of manufactured goods.

Finally, we note a few caveats regarding our analysis. First, as with most other studies in the literature, we use industry responses to past changes in energy prices to derive estimates of the effects of future carbon policy. That is, we assume that manufacturing plants would respond similarly to energy price increases induced by a carbon price as they have responded to historical price changes. The high degree of persistence of historical energy prices and carbon prices supports this assumption. Second, our analysis covers the short run, in which capital stocks are fixed and there is no entry and exit of plants. Modeling long-run effects that include capital investment, entry, and exit would be a useful direction for future research.

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Table 1. Mean Values by Group

Group	# of obs. (rounded)	Share of sample	Electricity cost share	Fuel cost share	Log of employment	Log of shipments	Log of value added	Log of gross operating profits
1	1,289,000	0.51	0.007	0.004	3.716	8.494	7.818	6.781
2	208,000	0.08	0.010	0.007	4.182	9.030	8.319	7.296
3	306,000	0.12	0.012	0.008	3.524	8.453	7.670	6.769
4	262,000	0.10	0.013	0.011	3.987	8.912	8.127	7.150
5	191,000	0.08	0.019	0.017	3.980	9.164	8.283	7.356
6	87,000	0.03	0.022	0.032	4.076	8.636	7.993	6.905
7	87,000	0.03	0.029	0.054	3.600	8.802	7.943	7.108
8	96,000	0.04	0.078	0.099	3.959	8.585	8.034	7.016
Full sample	2,527,000		0.015	0.015	3.797	8.646	7.927	6.928
(Std. dev.)			0.022	0.026	1.443	1.866	1.816	2.567

Notes: Groups based on energy cost share (sum of electricity and fuel costs, divided by shipments).

Table 2. Effects of Energy Prices on National Outcomes

Dependent variable is:

	Log real value of shipments	Log real value added	Log employment	Log real profits
Log electricity price	-0.01	-0.17	-0.04	-0.14
X cost share	(0.11)	(0.17)	(0.06)	(0.21)
Log fuels price	-0.15	-0.21	-0.04	-0.22
X cost share	(0.07)	(0.09)	(0.02)	(0.11)
Number of observations	13,749	13,749	13,749	13,727
R-squared	0.92	0.92	0.92	0.89

Notes: The table reports coefficient estimates from Equation (3), with standard errors in parentheses clustered by three-digit NAICS industry and year. See text for details.

Table 3. Simulation Results for $10 Carbon Price Applied to RGGI States
Including Variation with PA and NJ added to RGGI

Coverage	Carbon price	Industries	Outcome	RGGI states	PA+NJ	Near RGGI	Far RGGI
RGGI	electricity	all	employ	-2.71%	0.83%	0.29%	0.12%
RGGI	electricity	all	output	-3.81%	0.67%	0.20%	0.06%
RGGI	electricity	all	profits	-4.16%	0.31%	-0.03%	-0.17%
RGGI	electricity	high-energy	employ	-7.08%	1.76%	0.61%	0.37%
RGGI	electricity	high-energy	output	-10.51%	1.01%	0.56%	0.42%
RGGI	electricity	high-energy	profits	-11.24%	0.16%	0.23%	0.16%
RGGI_PA_NJ	electricity	all	employ	-2.22%	-3.32%	0.67%	0.28%
RGGI_PA_NJ	electricity	all	output	-3.37%	-4.91%	0.52%	0.18%
RGGI_PA_NJ	electricity	all	profits	-3.90%	-5.09%	0.01%	-0.27%
RGGI_PA_NJ	electricity	high-energy	employ	-5.73%	-7.82%	1.59%	0.85%
RGGI_PA_NJ	electricity	high-energy	output	-9.64%	-11.01%	1.42%	0.94%
RGGI_PA_NJ	electricity	high-energy	profits	-11.30%	-12.17%	0.36%	0.25%
RGGI	electric+fuels	all	employ	-2.04%	0.77%	0.26%	0.12%
RGGI	electric+fuels	all	output	-2.76%	0.75%	0.31%	0.20%
RGGI	electric+fuels	all	profits	-3.00%	0.61%	0.18%	0.08%
RGGI	electric+fuels	high-energy	employ	-6.62%	1.32%	0.61%	0.50%
RGGI	electric+fuels	high-energy	output	-9.59%	0.99%	0.74%	0.73%
RGGI	electric+fuels	high-energy	profits	-10.42%	0.75%	0.59%	0.65%
RGGI_PA_NJ	electric+fuels	all	employ	-1.59%	-2.57%	0.62%	0.27%
RGGI_PA_NJ	electric+fuels	all	output	-2.28%	-3.38%	0.72%	0.42%
RGGI_PA_NJ	electric+fuels	all	profits	-2.59%	-3.53%	0.42%	0.17%
RGGI_PA_NJ	electric+fuels	high-energy	employ	-5.62%	-7.04%	1.44%	1.01%
RGGI_PA_NJ	electric+fuels	high-energy	output	-8.67%	-8.77%	1.76%	1.46%
RGGI_PA_NJ	electric+fuels	high-energy	profits	-9.91%	-10.17%	1.23%	1.14%

Notes: Simulation results based on coefficients estimated in Equations (2) and (3). The table shows change in average outcome variable for plants located in specified regions, comparing no-policy ($0 carbon price) with a $10 carbon price applied to electricity prices (or both electricity and fuels prices) faced by all plants located in the RGGI region (expanded in some simulations to include Pennsylvania and New Jersey). Results shown separately for all manufacturing industries and those designated as high-energy-cost industries (groups 5-8 in Table 1).

RGGI states: CT, DE, MA, MD, ME, NH, NY, RI, VT.
Near-RGGI states: IN, KY, MI, NC, OH, VA, WV.
Far-RGGI states: AL, FL, GA, IL, MS, SC, TN, WI.

Figure 1. Comparison of All-Manufacturing and High-Energy-Cost-Industry Trends

Figure 1A. Energy Price and Energy Cost Share

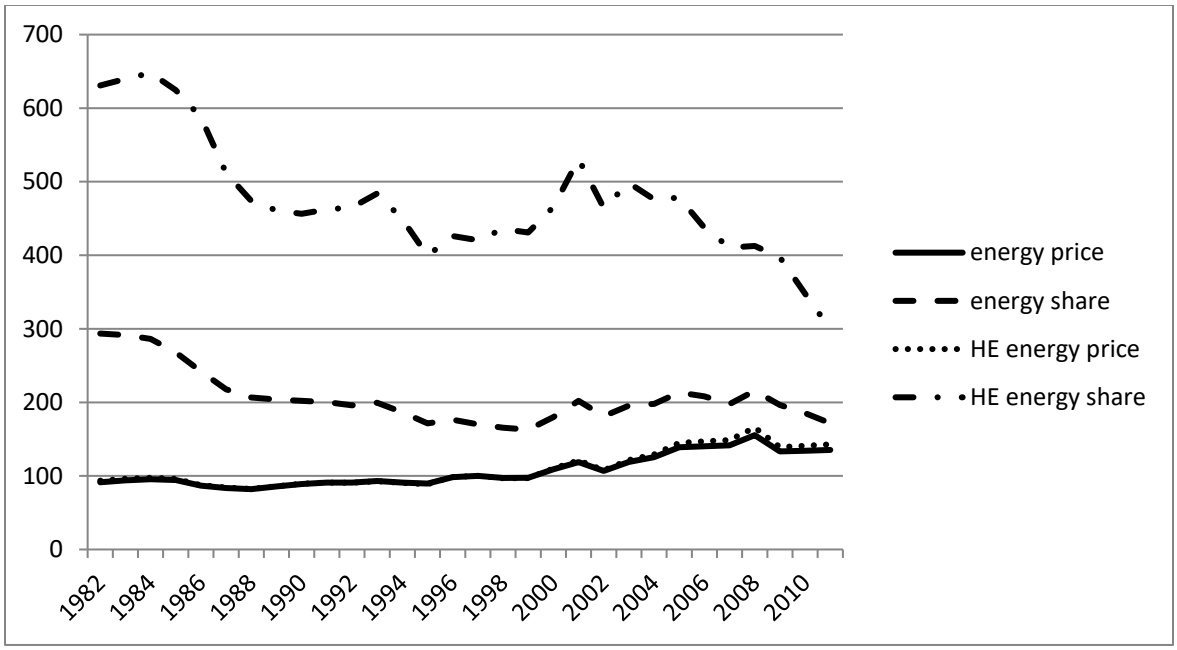
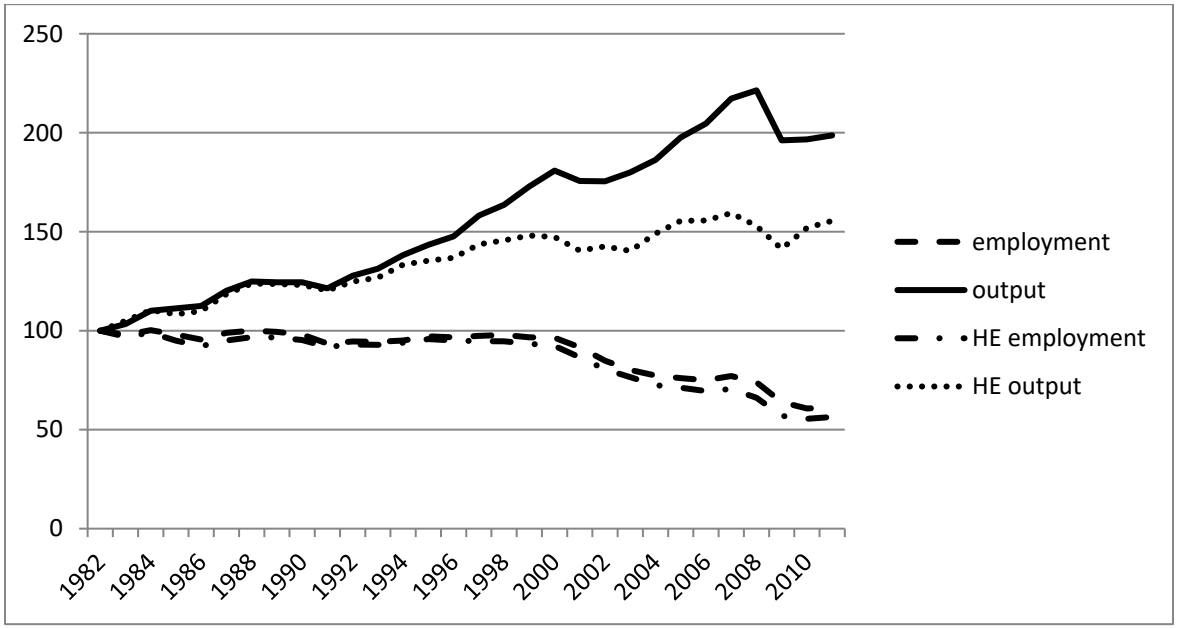


Figure 1B. Employment and Output



Notes: These figures compare the average values for all manufacturing industries with the average values for the high-energy-cost industries in Groups 5–8. Energy cost shares are scaled, setting 100 = one percent cost share; all other variables are normalized to 100 in 1982. All numbers based on industry-level data from NBER-CES Manufacturing Industry Database.

Figure 2. Energy Price Variation Across States in 2011

Figure 2A. 2011 Electricity Prices

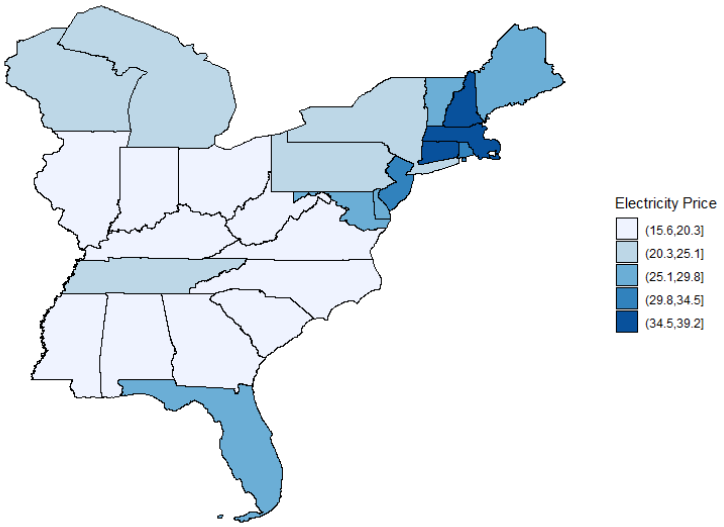
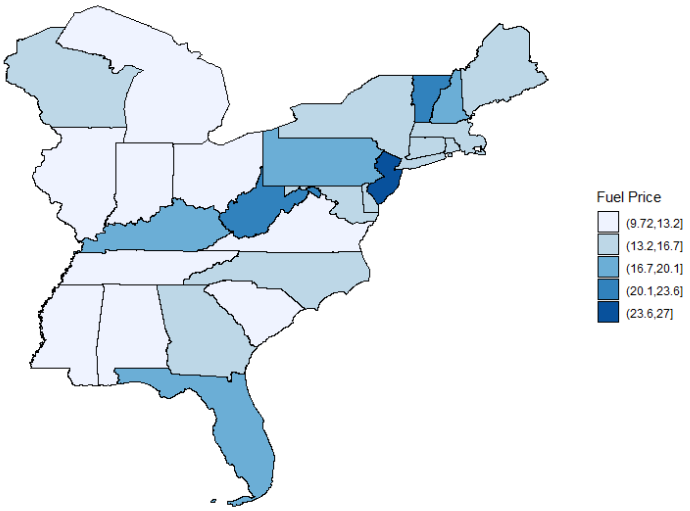
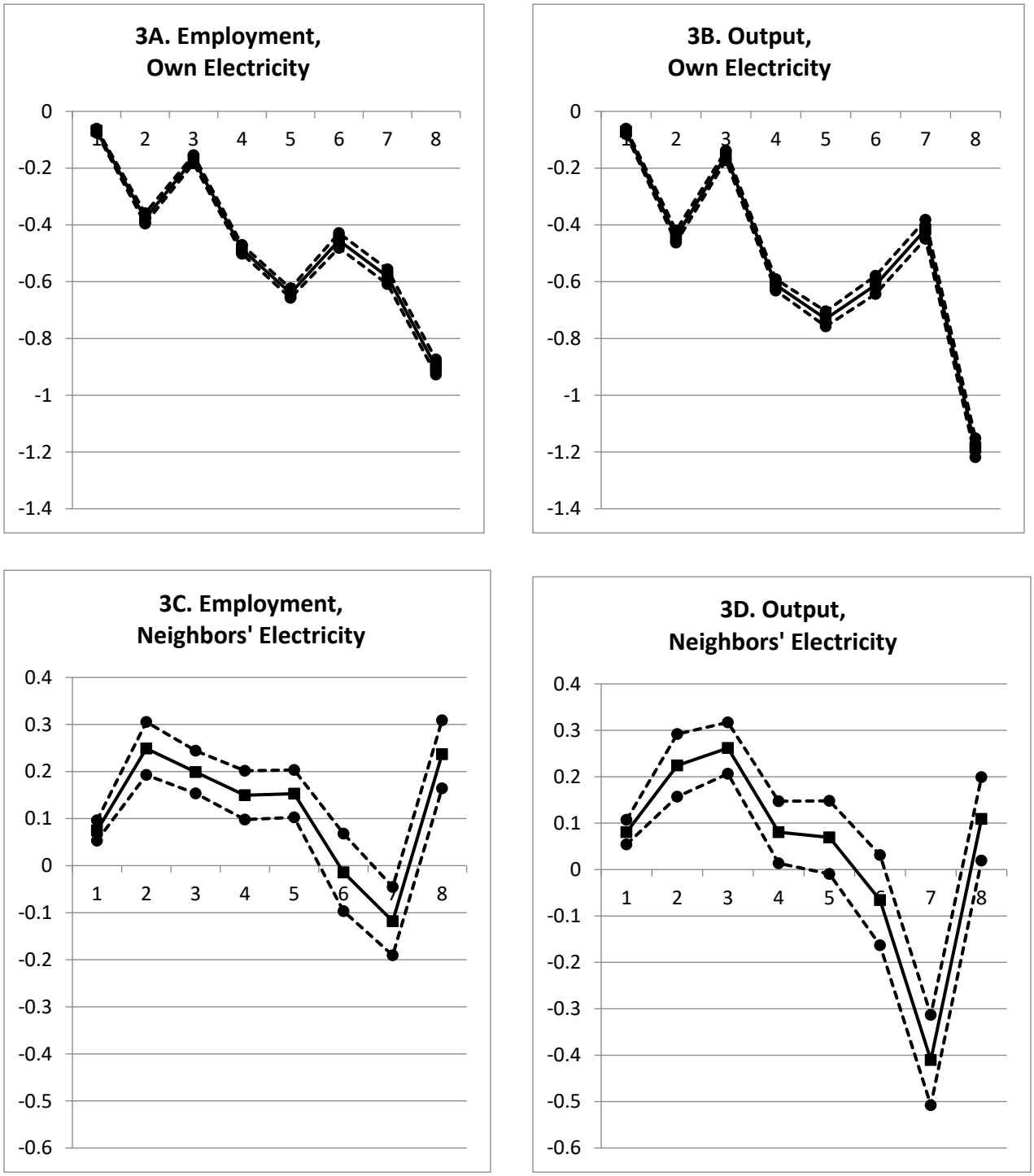


Figure 2B. 2011 Fuels Prices



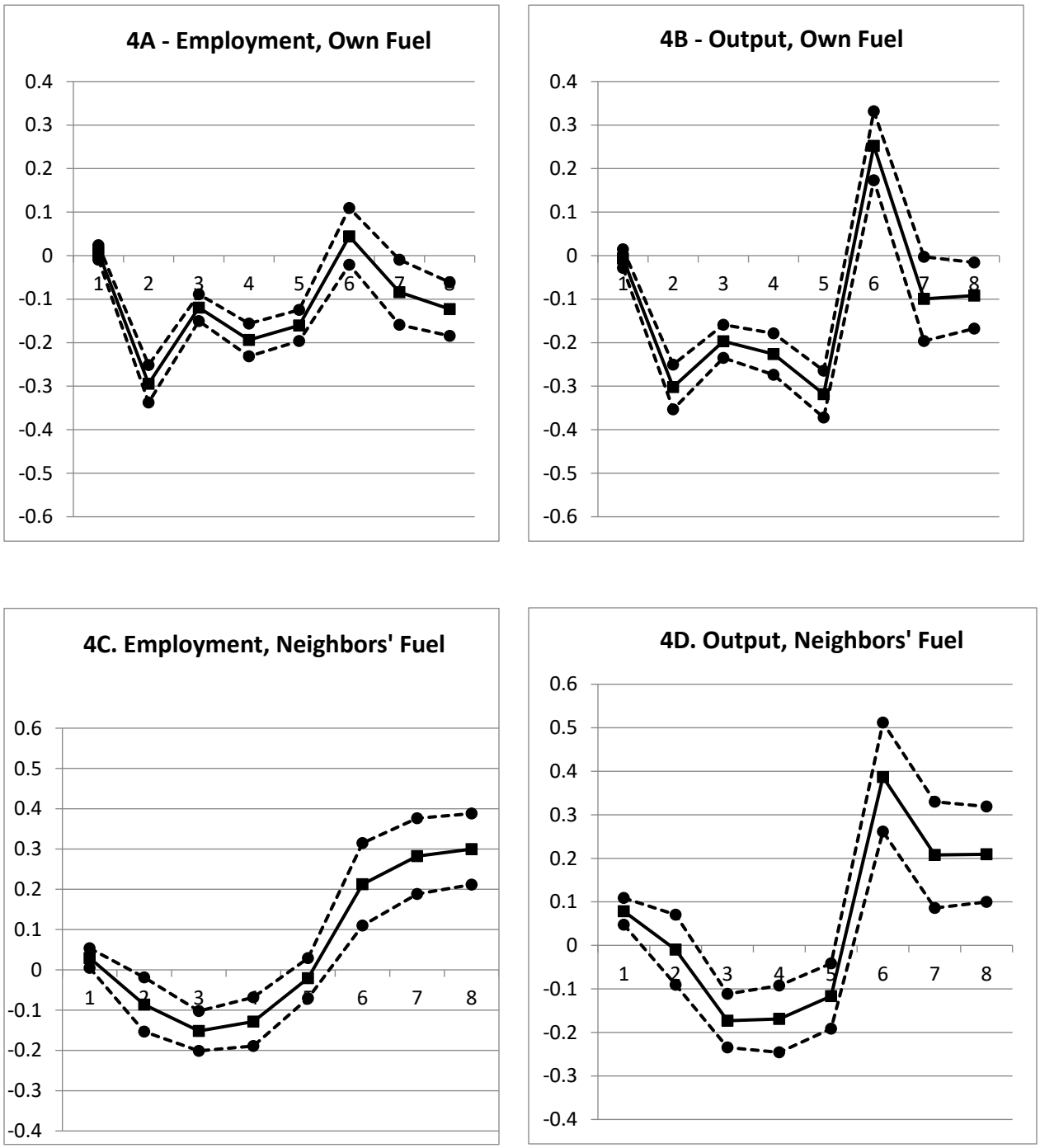
Notes: Both electricity and fuels prices come from the State Energy Data System (SEDS) provided by the US Energy Information Administration (https://www.eia.gov/state/seds/) and are expressed in dollars per million BTU. The electricity price is that paid by industrial consumers in the state. The fuels price includes coal, natural gas, distillate fuel oil, residual fuel oil, and hydrocarbon gas liquids, aggregating the total amount spent on those fuels by industrial consumers in the state and dividing by their total BTU content.

Figure 3. Employment and Output Elasticities with Respect to Electricity Prices



Notes: Estimated elasticity of outcome variables with respect to electricity prices (both own price and neighbor price), based on coefficients from Equation 2, which is estimated separately for 8 industry groups shown in Table 1 (Group 1 is lowest energy cost share; Group 8 is highest).

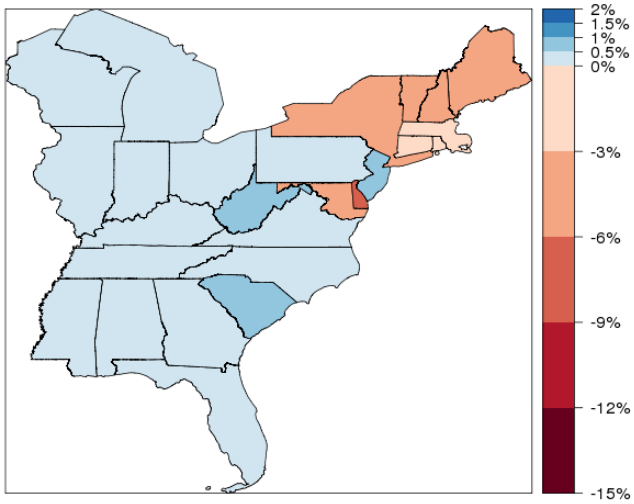
Figure 4. Employment and Output Elasticities with Respect to Fuels Prices



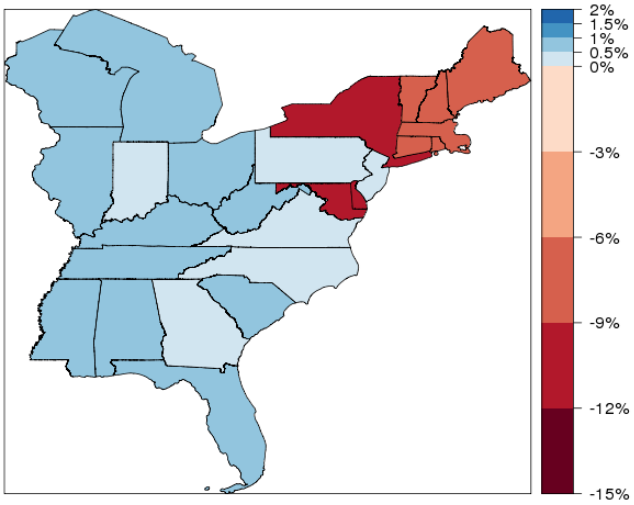
Notes: Estimated elasticity of outcome variables with respect to fuels prices (both own price and neighbor price), based on coefficients from Equation 2, which is estimated separately for 8 industry groups shown in Table 1 (Group 1 is lowest energy cost share; Group 8 is highest).

Figure 5. Employment and Output Changes with $10 Carbon Price on Electricity

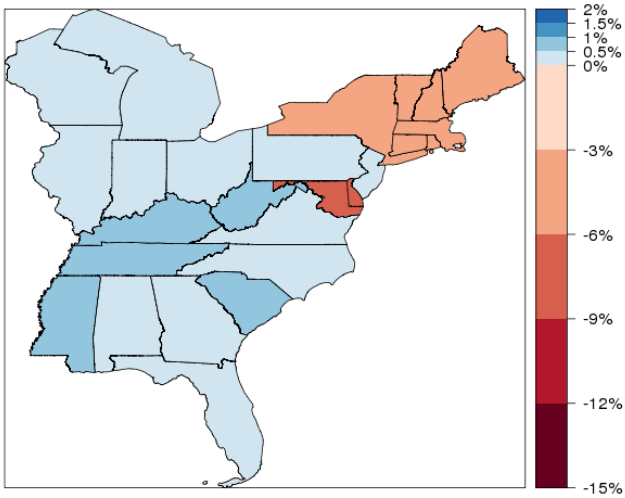
5A. Employment, All Industries



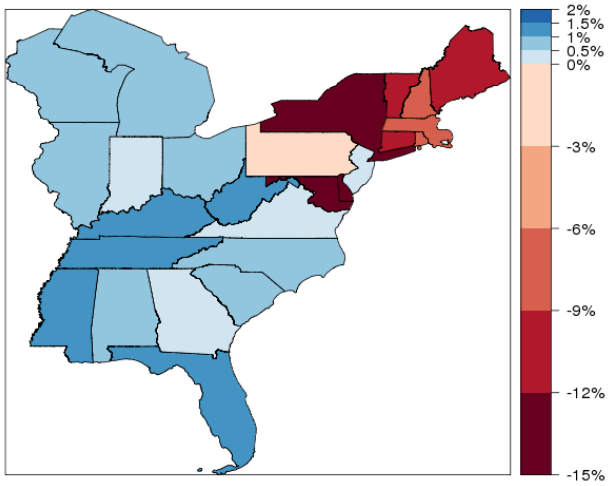
5B. Employment, High-Energy Industries



5C. Output, All Industries



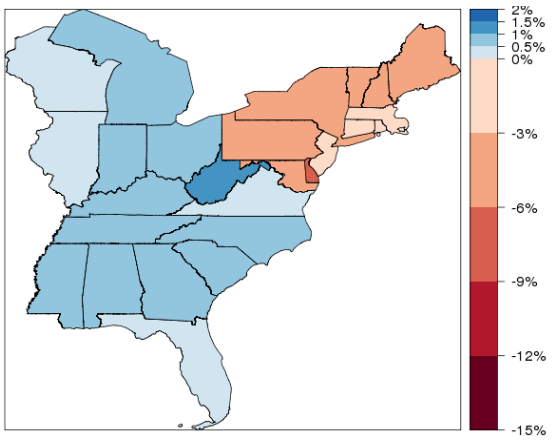
5D. Output, High-Energy Industries



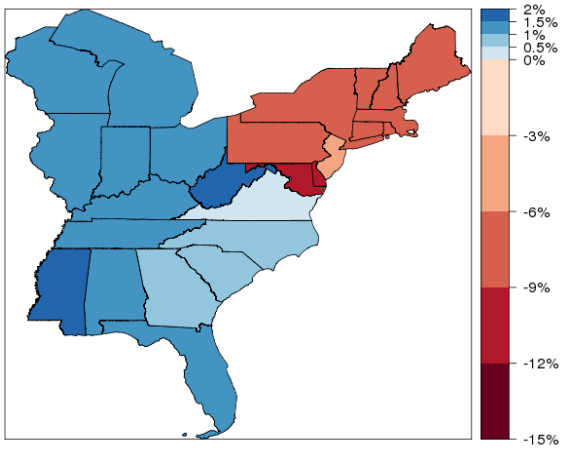
Notes: Simulation results based on coefficients estimated in Equations (2) and (3). The figures show the change in average employment and output for plants located in each state, comparing no-policy ($0 carbon price) with a $10 carbon price applied to electricity prices faced by all plants located in the RGGI region. Results shown separately for all manufacturing industries and those designated as high-energy industries (Groups 5-8 in Table 1).

Figure 6. Employment and Output Effects: Adding PA and NJ to RGGI with $10 Carbon Price on Electricity

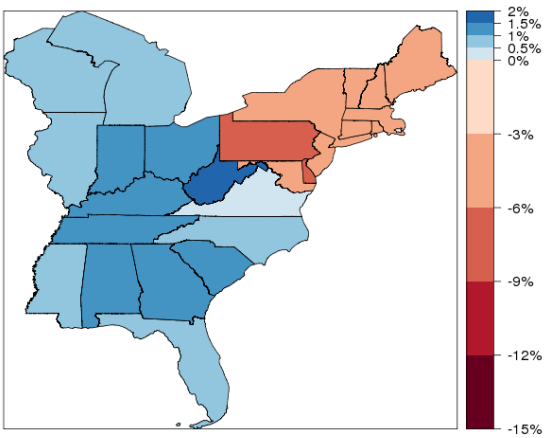
6A. Employment, All Industries



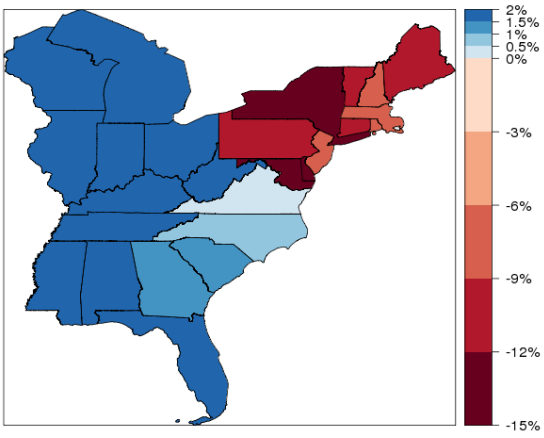
6B. Employment, High-Energy Industries



6C. Output, All Industries



6D. Output, High-Energy Industries

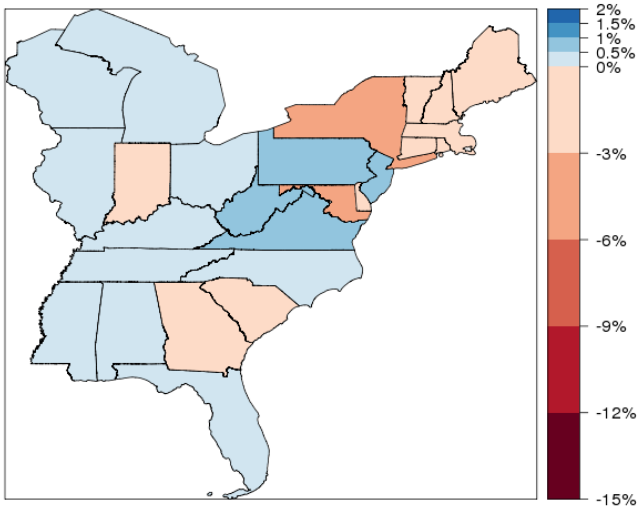


Notes: Simulation results based on coefficients estimated in Equations (2) and (3). The figure shows the change in average employment and output for plants located in each state, comparing no-policy ($0 carbon price) with a $10 carbon price applied to electricity prices faced by all plants located in the RGGI region as well as Pennsylvania and New Jersey. Results shown separately for all manufacturing industries and those designated as high-energy industries (Groups 5-8 in Table 1).

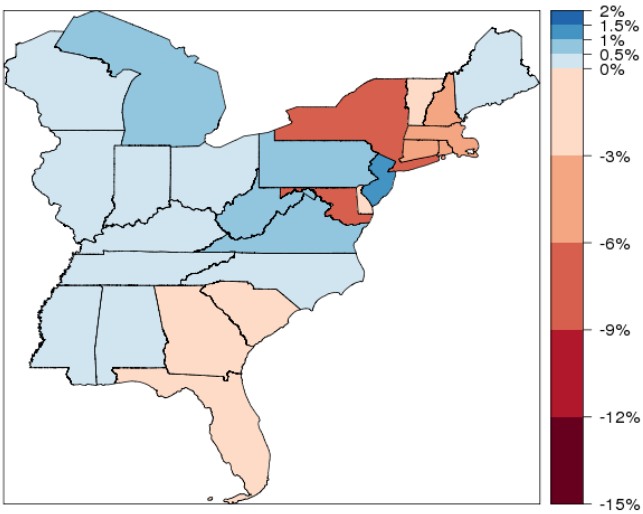
Figure 7. Alternative Scenarios

Employment Changes with $10 Carbon Price on Both Electricity and Fuels

7A. Employment, All Industries



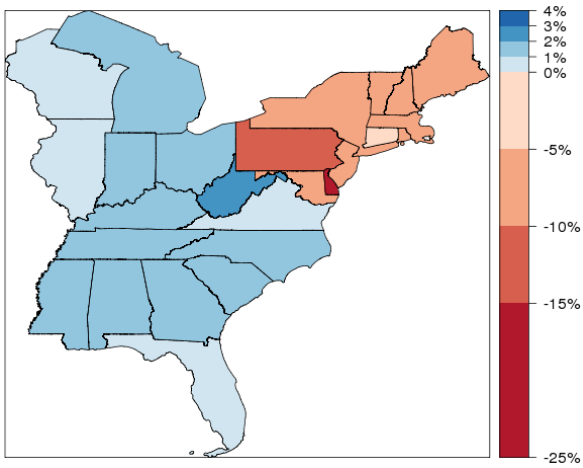
7B. Employment, High-Energy Industries



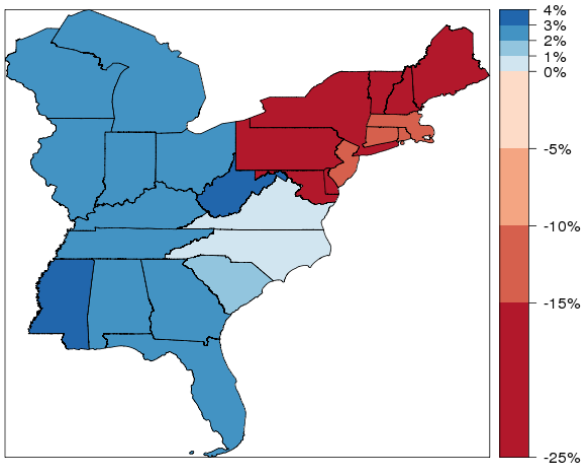
Notes: Change in average employment comparing no-policy ($0 carbon price) with a $10 carbon price applied to electricity and fuels prices faced by all plants located in the RGGI region. Results shown separately for all manufacturing and high-energy industries (Groups 5-8 in Table 1).

Employment Changes: Adding PA and NJ to RGGI with $25 Carbon Price on Electricity

7C. Employment, All Industries



7D. Employment, High-Energy Industries



Notes: Change in average employment comparing no-policy ($0 carbon price) with a $25 carbon price applied to electricity prices faced by all plants located in the RGGI region as well as Pennsylvania and New Jersey. Results shown separately for all manufacturing and high-energy industries (Groups 5-8 in Table 1).

TOWARD GREENER FERC REGULATION OF THE POWER INDUSTRY

Christopher J. Bateman and James T. B. Tripp***

America's electricity industry is at the heart of some of the nation's and world's biggest environmental challenges, including climate change. Yet the Federal Energy Regulatory Commission ("FERC"), which has regulatory jurisdiction over wholesale sales and transmission of electricity in interstate commerce and is charged with ensuring that rates and other aspects of the industry are "just and reasonable," has an official policy of excluding environmental considerations from its regulation of the industry. This Article traces the evolution of this policy and argues that it is time for a new and better approach—one that integrates economic and environmental regulation of the industry, helps the United States achieve a clean energy future, and reduces excessive environmental impacts.

This Article explores the possibility of such an approach under the Federal Power Act ("FPA"), which provides FERC's mandate. In doing so, it addresses FERC's reasoning for its current policy and finds these reasons unpersuasive as a matter of law and policy. Contrary to FERC's position, it is plausible to view the FPA alongside other federal laws as being silent or ambiguous about FERC's environmental authority, thus permitting an environmentally inclusive approach within reasonable constraints. This reading of the FPA is reinforced by a host of policy considerations: the urgent need to address the U.S. electricity industry's significant contribution to climate change; the inadequacy of and continuing uncertainty surrounding existing regulatory efforts on this front; FERC's expertise in aspects of the electricity industry important to effective design and implementation of regulatory solutions; the unique nature of greenhouse gas emissions as pollutants and the feasibility of FERC regulation of carbon emissions in particular; and the glaring problems with our schizophrenic approach to energy regulation, in which environmental regulation and traditional utility regulation often undermine each other, creating inefficiencies.

This Article offers a number of concrete examples of the types of progressive industry reforms that would be possible if FERC adopted an environmentally inclusive approach, while also acknowledging and exploring the limits and challenges of this approach. On balance, the rewards seem to far outweigh the risks. Incorporating environmental considerations would allow FERC to make better informed decisions about how to maximize social welfare in areas such as transmission planning and organized electricity markets, and could create possibilities for productive collaborations with other regulatory authorities, including the Environmental Protection Agency, to guide the nation toward smarter energy policy.

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* Christopher Bateman is a member of the Class of 2014 at Harvard Law School and a former legal intern at the Environmental Defense Fund ("EDF").

** James T. B. Tripp is senior counsel at EDF, which has participated in some of the regulatory proceedings described in this Article. The authors would like to thank Richard Lazarus, Sharon Jacobs, Elizabeth Stein, and John Moore for their extremely helpful feedback and ideas. We would also like to thank Will Sears and Jesse Glickenhaus for their research and ideas that helped stimulate some of the thinking behind this Article. Thank you to the *Harvard Environmental Law Review* editing staff for their hard work and editing contributions.

Introduction

Suppose an electric utility is looking to buy some electricity to resell to its customers. The utility needs to buy one megawatt-hour of energy, and it can buy from either of two power plants—one a coal plant, one a wind farm. The coal plant will sell the energy for fifty dollars. The wind farm will sell the energy for sixty dollars. If the coal plant generates the energy, it will emit one metric ton of carbon dioxide ("CO_2"). These emissions, with their contribution to global warming and its effects on agricultural productivity, sea levels, storm frequency and intensity, human health, industry, and ecosystems,[1] will end up costing society forty dollars when all is said and done. If the wind farm generates the energy, it will produce no emissions.[2] The utility does not have to pay the cost of the emissions. The utility buys its megawatt-hour of electricity from the coal plant for fifty dollars. The total cost to society of the transaction is ninety dollars: the fifty dollars the utility paid, plus the forty dollars society will pay, down the road, for the emissions. Had the utility bought from the wind farm, the total cost to society would have been just sixty dollars.

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[1] *See* Thomas F. Stocker ets al., *Technical Summary*, *in* Intergovernmental Panel on Climate Change, Climate Change 2013—The Physical Science Basis: Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change 89–113 (2013) [hereinafter IPCC 2013], *available at* http://perma.cc/WY89-X9DN (discussing predicted long-term effects of climate change on sea levels and storm patterns); M.L. Parry et al., *Summary for Policymakers*, *in* Climate Change 2007—Impacts, Adaptation and Vulnerability: Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change 11–12 (2007), *available at* http://perma.cc/ZC68-FMXX (discussing predicted effects on agricultural productivity, human health, industry, and ecosystems).

[2] For simplicity's sake, we do not consider full lifecycle emissions in this example. For a description of lifecycle analysis, see *infra* note 35.

This scenario represents a simplified but instructive abstraction of how many electricity sales in the United States take place. Now pretend you are a regulator presiding over this transaction, with a mandate to regulate in the public interest and to ensure that wholesale electricity rates are "just and reasonable."[3] Did this transaction live up to this standard? The answer of the Federal Energy Regulatory Commission ("FERC"), the regulator with this authority and mandate in the United States, is essentially "yes." In fact, FERC's policy is to ignore environmental considerations in its regulation of electricity rates entirely.

Why would FERC reach these conclusions? How did its approach to regulation evolve to arrive at this position? Is FERC's approach, as a matter of law and policy, the right approach at a time when energy and environmental problems are thoroughly interwoven, or would it make more sense for FERC to take into account the cost to society of these emissions? These questions are the topic of this Article.

Significant gaps exist in U.S. environmental regulation of the electricity industry, causing society to bear excessive environmental costs. Perhaps the most notable example is the lack of comprehensive regulation of greenhouse gas ("GHG") emissions from electricity generation. Electricity generation is responsible for about one third of U.S. GHG emissions.[4] Yet comprehensive regulation that would reduce the costs of these emissions to what welfare economics would call efficient (welfare-maximizing) levels is lacking. More broadly, a divide between environmental regulation and "energy" or "economic" or electric-utility regulation causes major environmental issues related to the electricity industry to fall through the cracks.[5]

FERC has broad regulatory power over the nation's electricity industry, including over interstate electricity transmission and wholesale electricity sales. The Federal Power Act[6] ("FPA") declares that the industry is "affected with a public interest,"[7] and sections 205 and 206 of the FPA charge FERC with ensuring that rates, charges, rules, regulations, and practices related to the transmission and wholesale sale of electricity in interstate commerce are "just and reasonable."[8] Since 1935, FERC has regulated transmission rates and wholesale sales by "public utilities"[9] under these provisions, and in recent decades

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[3] We have also simplified the nature of FERC's regulatory mandate for the sake of this thought exercise. As this Article will explore, FERC's mandate is more complex than this, and FERC has relied in part on other provisions of its organic statute to reach its current policy position.

[4] EPA, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012 ES-22 (2014) [hereinafter GHG Inventory], *available at* http://perma.cc/NJA8-3RBW.

[5] *See generally* Lincoln L. Davies, *Alternative Energy and the Energy-Environment Disconnect*, 46 Idaho L. Rev. 473 (2010).

[6] 16 U.S.C. § 791-828(c) (2012).

[7] 16 U.S.C. § 824(a) (2012).

[8] 16 U.S.C. §§ 824d(a), 824e(a) (2012). For brevity's sake, we will often refer to FERC's regulation under sections 205 and 206 as its "rate regulation" throughout this Article.

[9] The FPA gives FERC jurisdiction over "public utilities," meaning, roughly, investor-owned utilities, since the FPA exempts government-owned utilities and rural electric cooperatives from FERC jurisdiction. 16 U.S.C. § 824(f).

has invoked the provisions to promulgate far-reaching regulations that have fundamentally reshaped the industry.

Yet FERC has never considered environmental issues to be part of this "just and reasonable" rate calculus. In fact, FERC has on several occasions explicitly rejected arguments that it should consider environmental costs as part of its rate oversight,[10] and the federal courts have reached similar conclusions.[11] FERC has maintained this position even in the face of a decades-long overall federal regulatory trend toward increasing consideration of environmental problems, particularly under the National Environmental Policy Act ("NEPA")[12] and executive orders requiring agencies (at least executive agencies) to perform cost-benefit analyses of their regulations.[13] These developments—including, most recently, increasing agency attention to the effects of agency action or inaction on GHG emissions—make FERC's position seem anachronistic and anomalous, especially given the agency's central role in overseeing the nation's heaviest-polluting industry. Moreover, a recent trend at FERC toward promulgating industry reforms with positive environmental effects, as well as statements by a recent FERC chairman, during his tenure, calling climate change a "priority,"[14] suggest that FERC's official policy is at odds with its aims, and that explicitly embracing environmental considerations may help the agency advance its own goals.

This Article argues for a rethinking of the way FERC approaches its rate regulation of transmission and wholesale electricity sales. It argues that FERC's longstanding position of ignoring environmental factors in this context is overdue for change, especially with respect to GHG emissions and CO_2 emissions in particular, and explores the possibility of reading the language of the FPA to allow consideration of such factors. It addresses FERC's justifications for ignoring environmental considerations and concludes that, although some of FERC's concerns have merit, these justifications are unpersuasive, and that there are compelling reasons for FERC to take a new approach. These reasons include FERC's integral role and expertise in shaping and overseeing elements of the electricity industry, such as electricity markets and transmission, that will be crucial to the nation's ability to realize a clean energy future; the desirability of bridging the environmental-energy regulatory divide; the fact that recent FERC actions under sections 205 and 206 suggest the agency is aiming to promote clean electricity and related environmental goals, and thus may be seeking to accomplish indirectly what it could accomplish more directly, transparently, and efficiently; and the urgent need to address the electricity industry's contribution to climate change.

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[10] *E.g.*, PSI Energy, Inc., 55 FERC ¶ 61,254, 61,811 (1991); Monongahela Power Co., 39 FERC ¶ 61,350, 62,096 (1987).
[11] *See* Grand Council of Crees (of Quebec) v. FERC, 198 F.3d 950, 957 (D.C. Cir. 2000).
[12] 42 U.S.C. §§ 4332–4345 (2006).
[13] *See* Exec. Order No. 12,866, 58 Fed. Reg. 51,735 (Oct. 4, 1993) [hereinafter Executive Order 12,866].
[14] Steven Mufson, *Energy Commission Chief Favors Aggressive Action on Climate Change*, WASH. POST, Mar. 21, 2009, http://perma.cc/M2YC-ZJAL.

Surprisingly little has been written focusing on FERC's environmental policy with respect to its regulation of the electricity industry.[15] No article has systematically traced the evolution of FERC's exclusion of environmental considerations from its rate regulation or thoroughly assessed FERC's justifications for its approach. Nor has any article thoroughly explored the possibility of interpreting the FPA to require or allow FERC to consider environmental factors.[16] Although, as this Article discusses, various groups and entities argued that FERC should consider certain environmental factors in the course of FERC proceedings and litigation in the 1980s and 1990s,[17] this Article offers the first sustained, comprehensive exploration of the possibility, and will attempt to grapple with many of the complex legal and policy issues raised in the process. Moreover, the Article draws on important developments since the 1990s that are relevant to the question of whether it is time for FERC to take a different approach.

Part I of the Article briefly examines one major environmental problem relating to the electricity industry, summarizing the social costs of GHG emissions and CO_2 emissions in particular, the contribution of U.S. electricity generation to these emissions, and how existing regulations at the federal and state levels collectively fall far short of addressing the problem. Part II provides a brief overview of the FPA, the history and current state of the electricity industry, and FERC's role in shaping and regulating the industry. Part III explores the evolution of FERC's position of excluding environmental considerations from its rate regulation. Part IV sets forth an argument, under current administrative law doctrine, in favor of interpreting the FPA to authorize FERC to take environmental considerations into account (triggering an obligation on the part of the agency, under NEPA, to consider the environmental consequences of its actions).

The basics of the argument are as follows: Contrary to FERC's position, Congress has not clearly stated whether FERC may consider environmental factors in its rate regulation. Given this ambiguity, it would be permissible for FERC to change its policy, and to interpret the Act as allowing it to consider environmental factors—a policy change warranted by the major social benefits that could result from bridging the environmental-energy regulatory divide. If

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[15] Significant articles on the subject include Jeremy Knee, *Rational Electricity Regulation: Environmental Impacts and the "Public Interest,"* 113 W. VA. L. REV. 739 (2011) and Jason Pinney, *The Federal Energy Regulatory Commission and Environmental Justice: Do the National Environmental Policy Act and the Clean Air Act Offer A Better Way?*, 30 B.C. ENVTL. AFF. L. REV. 353 (2003).

[16] Closest in this regard is Knee, *supra* note 15, which compellingly argues that FERC and other electric utility regulators should consider certain environmental factors under the "public interest" language common to their statutory mandates, and that courts should scrutinize their failure to do so under the hard look or arbitrary and capricious doctrine. *Id.* at 744. Knee's driving thesis is that the principles that have informed electric utility regulators' conception of their "public interest" mandates, as well as sound economics, support consideration of environmental factors to a limited extent. *Id.* at 765–88. In this Article, we examine the FPA's public interest language as well as other crucial provisions of the FPA and the relationship of FERC and the FPA to the Environmental Protection Agency and other environmental laws.

[17] *See infra* Part III.B.

the FPA were interpreted to give FERC this authority, the reasoning behind FERC's categorical exclusion of its rate regulation from NEPA would no longer hold; the Commission would be required to consider the environmental consequences of certain of its actions. Beyond that, FERC would have license to incorporate environmental costs and benefits into its substantive regulation—although we discuss how FERC should be constrained by the existence of federal statutes giving the Environmental Protection Agency ("EPA") and other agencies environmental regulatory authority.

Part V offers several concrete proposals showing how FERC could put this policy into practice—proposals that could lower the overall social cost of America's electricity consumption, and that could spur significant and much-needed investment in cleaner electricity generation and in energy efficiency and conservation. Parts IV and V place an emphasis on arguments and proposals for FERC action on GHG emissions and CO_2 emissions in particular, where we believe action is most needed and perhaps most justified, but encompass the possibility for action on other environmental issues as well. The Article concludes with a few summarizing remarks.

A final introductory note: This Article takes the FPA as a given and explores the possibility that FERC should take a new approach to interpreting and implementing the statute. The Article sets forth our best effort at an argument for why this approach should be considered both legally permissible and preferable as policy, yet it acknowledges the possibility that courts could find the approach impermissible, as well as the significant limitations that the approach would face if it were upheld. These difficulties suggest that the ideal solution may be for Congress to amend the FPA to give FERC the power to consider environmental issues in its rate regulation—an approach the authors of this Article wholly support.[18] If Congress acted, it could give FERC clear authority to consider environmental factors and could erase some of the jurisdictional barriers that might limit the effectiveness of environmentally conscious regulation by FERC under the current FPA. A congressional solution may be unlikely in the near future, however, given the current political gridlock in Congress[19] and the opposition, particularly from the fossil fuel industry and fossil-fuel-reliant utilities,[20] that such a proposal might face. That political reality is part of

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[18] *See* Re Restructuring of the Electric Utility Industry in Vermont, 174 P.U.R.4th 409, 473, 475–76 (Vt. Pub. Serv. Bd. 1996) (proposing that the FPA should be amended "to make it clear that FERC has both the authority and the responsibility to consider the environmental impacts of broad industry restructuring decisions"). *Cf.* Richard Lazarus, Chair Lecture Marking his Appointment to the Harvard Law School Howard J. and Katherine W. Aibel Professorship of Law: Environmental Lawlessness (Apr. 10, 2013), *available at* http://perma.cc/N9ZL-L7Y7 (discussing inadequacy of decades-old federal statutes for addressing new and contemporary environmental problems).

[19] *See* Chris Cillizza, *The Least Productive Congress Ever*, WASH. POST, Jul. 17, 2013, http://perma.cc/KUM9-CPM6.

[20] *See* Evan Mackinder, *Pro-Environment Groups Outmatched, Outspent in Battle Over Climate Change Legislation*, OPENSECRETSBLOG (Aug. 23, 2010, 12:45pm), http://perma.cc/D67K-H3LW (noting record $175 million of lobbying—outpacing spending by environmental groups eightfold—by the oil and gas industry in 2009, when Congress narrowly failed to pass cap-and-trade legislation).

why we focus our proposal on the administrative law route.[21] Moreover, we hope that the Article provides insight into the types of improved policies that would be possible under environmentally inclusive FERC regulation, regardless of how that new regulatory approach was reached.

I. Electricity's Environmental Costs: Carbon as a Case Study

To understand why there may be a need for FERC to assume environmental responsibilities, it is necessary to explore how existing environmental regulation of the electricity industry in the United States is inadequate. This Part examines what is surely the most pressing environmental problem relating to the industry, presenting an overview of the social costs of climate change and then surveying U.S. regulations that internalize the costs of GHG emissions from electricity or otherwise limit them. To be sure, electricity generation in the United States produces a host of other environmental problems, including air and water pollution, yet we focus here, and elsewhere in this Article, on the costs of climate change from GHG emissions because of its urgency and the important role FERC could play in this area.

A. What the Costs Are

i. Estimating the Social Cost of Carbon

Although the practice of quantifying and monetizing environmental harm is open to criticism on a number of grounds,[22] and estimates of the social costs of climate change vary widely, quantifying these costs and incorporating them into the prevailing cost-benefit approach to regulation may be the most effective and realistic way to address these environmental harms and reduce them to socially desired levels in the near future. Moreover, such an approach would be an appropriate one for FERC to take under the economically-oriented FPA, which charges FERC with ensuring that "rates," "charges," and "classifications" relating to wholesale sales and interstate transmission of electricity are just and reasonable.[23]

In 2010, a federal interagency working group produced a set of estimates of the social cost of carbon emissions for federal agencies "to incorporate the

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[21] *See* Jody Freeman & David B. Spence, *Old Statutes, New Problems*, Penn. L. Rev. (forthcoming 2014) (arguing that "congressional dysfunction invites agencies and courts to do the work of updating statutes," that "agencies are better suited than courts to do that updating work," and that "the case for deferring to agencies in that task is stronger than ever with Congress largely absent from the policymaking process").

[22] *See generally*, *e.g.*, Frank Ackerman & Lisa Heinzerling, *Pricing the Priceless: Cost-Benefit Analysis of Environmental Protection*, 150 U. Pa. L. Rev. 1553 (2002) (criticizing cost-benefit analysis in general and as used in the context of environmental regulation, partly because of the difficulty of monetizing environmental harm). Conventional economic approaches to environmental policymaking are also open to criticism for being overly anthropocentric and instrumentalist.

[23] *See* 16 U.S.C. § 824e (2012).

social benefits from reducing CO_2 emissions into cost-benefit analyses of regulatory actions that have small, or 'marginal,' impacts on cumulative global emissions."[24] In 2013, the group released a technical update of the estimates.[25] The social cost estimate "is intended to include . . . changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change."[26] The group has noted the high levels of uncertainty that currently inhere in attempting to predict and monetize the economic impacts of CO_2 emissions, but has developed a range of cost values using "a defensible set of input assumptions" grounded in three models used to study the impacts of climate change and frequently cited in peer-reviewed scientific literature.[27] The group's most recent set of estimates vary widely based on the discount rate used to translate future costs into current dollars, but the central value—the estimate most likely to be accurate given the models' predictions and a three percent discount rate—for the cost of carbon emitted in the year 2015 is thirty-eight dollars (in 2007 dollars) per metric ton of CO_2,[28] a figure likely to be adjusted in light of new research and advances in modeling.[29] The group has not provided an estimate for the social cost of other GHGs—which differ from CO_2 in aspects such as radiative forcing and atmospheric lifetime, so that different analyses are needed to estimate their social cost—but has stated that it hopes to offer estimates for these in the future.[30]

Additional studies have been done to estimate the social cost of CO_2[31] and other greenhouse gases.[32] The estimates vary considerably and are subject to large uncertainties and methodologies difficulties,[33] but we need not delve into

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[24] INTERAGENCY WORKING GROUP ON SOCIAL COST OF CARBON, U.S. GOV'T, TECHNICAL SUPPORT DOCUMENT: SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866, at 2 (2010) [hereinafter 2010 SOCIAL COST OF CARBON]. The document explains that "most federal regulatory actions can be expected to have marginal impacts on global emissions." *Id.*

[25] INTERAGENCY WORKING GROUP ON SOCIAL COST OF CARBON, UNITED STATES GOVERNMENT, TECHNICAL SUPPORT DOCUMENT: TECHNICAL UPDATE OF THE SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866 (2013) [hereinafter 2013 SOCIAL COST OF CARBON].

[26] *Id.* at 2.

[27] 2010 SOCIAL COST OF CARBON, *supra* note 24, at 3.

[28] 2013 SOCIAL COST OF CARBON, *supra* note 25, at 3, 12 (noting how the three percent discount rate figure is the "central" estimate). $38 in 2007 dollars translates into $42.69 in 2013 dollars. *See* BUREAU OF LABOR STATISTICS, CPI INFLATION CALCULATOR, http://perma.cc/4KAX-TCT6.

[29] *See* 2010 SOCIAL COST OF CARBON, *supra* note 24, at 4.

[30] *Id.* at 12.

[31] *See* Richard S. J. Tol, *The Social Cost of Carbon*, 3 ANN. REV. OF RESOURCE ECON. 419 (2011) (containing a meta-analysis of numerous studies).

[32] *E.g.*, Samuel Fankhauser, *The Social Costs of Greenhouse Gas Emissions: An Expected Value Approach*, 15 ENERGY J. 157 (1994).

[33] *See* Tol, *supra* note 31, at 429–35 (summarizing variation). EPA cautions that "'it is very likely'" that estimates of the social cost of carbon ("SCC") underestimate the damages from climate change, adding that "[t]he models used to develop SCC estimates, known as integrated assessment models, do not currently include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models naturally lags behind the most recent research." *The Social Cost of Carbon*, EPA.GOV, http://perma.cc/7KMF-MJPY. Tol explains that newer SCC models "tend to assume that [human]

these intricacies for purposes of this Article. We need only observe that the estimated cost of carbon emissions is significant, and that FERC could rely on the federal interagency group estimates if it were to adopt proposals like the ones put forth in this Article.

ii. The Contribution of Electricity Generation to GHG Emissions

Electricity generation is a huge contributor to U.S. GHG emissions, constituting thirty-eight percent of all U.S. CO_2 emissions and thirty-one percent of GHG emissions (on a global warming potential-weighted basis) in 2012.[34] The GHG efficiency of generation varies widely by type of generation. On a lifecycle basis,[35] fossil fuel powered plants are orders of magnitude less GHG-efficient than renewable facilities like solar and wind plants; one meta-analysis estimated the typical coal plant had a lifecycle GHG efficiency of 1,000 grams of CO_2 equivalent per kilowatt-hour of electricity generated, with natural gas being twice as efficient as that, solar photovoltaic about thirty times as efficient, and wind about 110 times as efficient.[36]

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agents have perfect foresight about climate change and have the flexibility and appropriate incentives to respond" and adapt, Tol, *supra* note 31, at 424; that many climate effects, including potentially large ones, remain unquantified in the models, *id.* at 426; that the models have difficulty valuing damage to ecosystems, *id.* at 428; and that the level of uncertainty involved is "large and probably understated — especially in terms of failing to capture the risk of large welfare losses", *id.* at 425; *see also* PETER HOWARD, OMITTED DAMAGES: WHAT'S MISSING FROM THE SOCIAL COST OF CARBON 1 (2014) (study funded by EDF, Institute for Policy Integrity, and the Natural Resources Defense Council finding that the updated federal interagency working group estimate "should be viewed as a lower bound" since it omits many climate impacts and includes only a portion of potential harms for included impacts, as the study goes on to analyze).

[34] *See* GHG INVENTORY, *supra* note 4, at ES-5, Table ES-2 (listing CO_2 emissions), ES-22–ES-23 (listing total GHG emissions).

[35] A lifecycle analysis or assessment ("LCA") is "a technique to assess the environmental aspects and potential impacts associated with a product, process, or service" by "[c]ompiling an inventory of relevant energy and material inputs and environmental releases" and "[e]valuating the potential environmental impacts associated with identified inputs and releases." *Life Cycle Assessment (LCA)*, EPA.GOV, http://perma.cc/N55G-VYD8. The major stages in an LCA are raw material acquisition, materials manufacture, production, use/reuse/maintenance, and waste management. *Id.* For an example of a regulatory program using lifecycle analysis, see CAL. CODE REGS. tit. 17, § 95481 (2012) (using lifecycle emissions to define carbon intensity).

[36] Benjamin K. Sovacool, *Valuing the Greenhouse Gas Emissions from Nuclear Power: A Critical Survey*, 36 ENERGY POLICY 2940, 2950 (2008). While natural gas has significant advantages over coal and oil in terms of its combustion carbon dioxide emissions, its impact on global warming also depends on its methane emissions during production, processing, and distribution. According to the IPCC 5th Assessment Report, methane is eighty-six times more potent than CO_2 as a climate forcer over a twenty-year time horizon and thirty-four times more potent over 100 years. IPCC 2013, *supra* note 1, at 714. Until recently, direct monitoring and regulation of such methane emissions have been very limited. The Environmental Defense Fund and a number of universities and energy companies are together conducting field investigations of methane emissions and improving monitoring techniques. David T. Allen et al., *Measurements of Methane Emissions at Natural Gas Production Sites in the United States*, 110 PROC. OF NAT. ACAD. SCI. 17,768, 17,768 (2013). EPA will be indirectly regulating methane emissions from new natural gas wells in its 2012 New Source Performance Standards pursuant to section 111 of the Clean Air Act. 77 Fed. Reg. 49,490, 49,492–93 (2012) (to be codified at 40 C.F.R. pts. 60, 63). The first state regulatory agency to adopt methane emission monitoring requirements is the Colorado Air Quality Control Commission, in its Regulation 7. 5 Colo. Code Regs. §§ 1001-5, 1001-8, 1001-9 (2014).

GHG emissions from coal generation, the dominant source of electricity in the United States, contributed 24.5% of all U.S. GHG emissions on a global warming potential-weighted basis in 2012.[37] While coal has declined over the past few years as a fuel source for generation in the United States,[38] fossil fuels remain the dominant source of electricity. In 2012, 37.6% of U.S. electricity came from coal, 30.3% from natural gas, 19% from nuclear, 7% from hydropower, 3% from wind, and 0.1% from solar.[39]

Using the central federal interagency estimate of the social cost of carbon, we can calculate that CO_2 emissions from U.S. electricity generation in 2010 alone are projected to cost the world about seventy-six billion in today's dollars.[40]

B. A Lack of Adequate Solutions

U.S. regulation related to GHG emissions from electricity generation currently consists of a patchwork of various kinds of state, regional, and federal programs. Although it is difficult to compare the impacts of the different types of regulation, and EPA efforts have been accelerating, the many state and regional programs arguably have a greater impact collectively than the federal programs.[41]

i. Federal Regulation

a. EPA Initiatives

Legislation to address GHG emissions through a national cap-and-trade system died in Congress in 2009, and no serious congressional attempts to address the issue have occurred since.[42] That has left the task of regulating these emissions to EPA, which has taken two significant actions toward regulating GHG emissions from electricity generation. These are: (1) including GHG emissions in the Prevention of Significant Deterioration ("PSD") and Title V

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[37] *See* GHG Inventory, *supra* note 4, at 3-6, ES-4 (showing that electricity generation from coal is responsible for 1,594.0 out of the 6,501.5 teragrams of CO_2 equivalent emitted in the United States in 2012).

[38] Coal constituted thirty-nine percent of net U.S. generation in 2013, down from forty-eight percent in 2008. *See* U.S. Energy Information Administration, Electric Power Monthly with Data for January 2014 15 tbl.1.1 (2014), *available at* http://perma.cc/9RY7-LGCJ.

[39] U.S. Energy Information Administration, Short-Term Energy Outlook tbl.7d (2013).

[40] Derived by multiplying thirty-three dollars per metric ton of CO_2 (the central estimate for the cost of carbon emitted in 2010, expressed in 2007 dollars) by 2,023.6 million metric tons of CO_2 and adjusting for inflation. *See* 2013 Social Cost of Carbon, *supra* note 25, at 3; GHG Inventory, *supra* note 4, at ES-5. This assumes roughly fourteen percent total inflation between 2007 and 2014.

[41] *See* Philip A. Wallach, U.S. Regulation of Greenhouse Gas Emissions 2 (2012), *available at* http://perma.cc/Q8G3-R948 (asserting that federal actions can seem like a "sideshow" compared to state and regional actions in this area).

[42] *Id.* at 4.

Operating Permit Programs, and (2) proposing a Carbon Pollution Standard for New Power Plants.

The inclusion of GHG emissions in the PSD Permit Program means that very large GHG emitters have to obtain PSD permits under the Clean Air Act for their GHG emissions if they are newly constructed or undertake modifications that will increase GHG emissions by a certain threshold.[43] The PSD program requires the source to apply the best available control technology ("BACT") to control its GHG emissions.[44] BACT is determined on a case-by-case basis taking into account, among other factors, the cost and effectiveness of the control.[45] EPA has provided guidance about available and emerging BACT technologies (such as carbon capture and sequestration)[46] but has not endorsed or required any control strategy, instead leaving the states discretion to determine what constitutes BACT on a case-by-case basis.[47] The Court of Appeals for the District of Columbia upheld EPA's decision to regulate GHG emissions from stationary sources under the PSD and Title V programs.[48] The United States Supreme Court granted certiorari in October 2013 to review an important aspect of EPA's action[49] and heard oral argument in the matter in February 2014.[50]

EPA's revised proposed Carbon Pollution Standard for New Power Plants would require that fossil-fuel-burning power plants constructed in the future produce no more than 1,000 or 1,100 pounds (depending on the plant type) of CO_2 per megawatt-hour of electricity generated.[51] The regulation would not affect existing power plants.

While these efforts are significant, they remain subject to considerable legal and implementation uncertainty, and it remains to be seen how successful they will be in reducing GHG emissions.

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[43] *See* EPA, Fact Sheet: Final Rule - Prevention of Significant Deterioration and Title V Operating Permit Greenhouse Gas (GHG) Tailoring Rule Step 3 and GHG Plantwide Applicability Limits, at 1 [hereinafter Tailoring Rule Step 3 Fact Sheet], *available at* http://perma.cc/P77V-885A. This will include a large number of power plants: A typical 500 megawatt coal-fired baseload power plant emits about three million tons of CO_2 equivalent annually. LARRY PARKER & JAMES E. MCCARTHY, CONG. RES. SERV., R41505, EPA'S BACT GUIDANCE FOR GREENHOUSE GASES FROM STATIONARY SOURCES (2010), *available at* http://perma.cc/5SCS-724B. Facilities that must obtain a PSD permit anyway, to cover other regulated pollutants, must also address GHG emissions increases of 75,000 tons per year CO_2 equivalent or more. Tailoring Rule Step 3 Fact Sheet, *supra*, at 1. Title V does not impose any independent substantive emissions limitations, so we do not discuss the Title V requirements relating to GHG emissions.

[44] 42 U.S.C. § 7475(a)(4) (2012).

[45] 42 U.S.C. § 7479(3) (2012); 40 C.F.R. § 52.21(b)(12) (2013); *see also* PARKER & MCCARTHY, *supra* note 43, at 2.

[46] EPA, AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM COAL-FIRED ELECTRIC GENERATING UNITS 25–26 (2010).

[47] *See* PARKER & MCCARTHY, *supra* note 43, at Summary.

[48] Coal. for Responsible Regulation, Inc. v. EPA, 684 F.3d 102, 113 (D.C. Cir. 2012).

[49] Util. Air Regulatory Group v. EPA, 134 S. Ct. 418 (2013).

[50] Transcript of Oral Argument, Util. Air Regulatory Group v. EPA, No. 12-1146 (S. Ct. argued Feb. 24, 2014), *available at* http://perma.cc/UKT9-8ZJG.

[51] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1429, 1433 (proposed Jan. 8, 2014) (to be codified at 40 C.F.R. pts. 60, 70, 71, 98).

b. Tax Incentives

Federal law provides tax incentives for certain types of renewable generation. The Production Tax Credit[52] is the centerpiece of these incentives.[53] The amount of the credit is currently 2.3 cents per kilowatt-hour for wind, geothermal, and closed-loop biomass facilities, and 1.1 cents per kilowatt-hour for open-loop biomass, landfill gas, municipal solid waste, hydroelectric, and marine and hydrokinetic facilities.[54]

ii. State Regulation

a. Cap-and-Trade Programs

Two cap-and-trade programs are currently in force at the state/regional level. One is the Regional Greenhouse Gas Initiative ("RGGI"), a cooperative effort by nine northeastern states to reduce CO_2 emissions from power plants in these states by ten percent from 2009 levels by 2018.[55] RGGI establishes a cap representing the target level of CO_2 emissions from power plants with capacity of twenty-five megawatts or more in the region (168 plants as of 2012) in a given year.[56] The original cap aimed to stabilize CO_2 emissions until 2015, but the 2014 cap was lowered after a 2012 program review because there was an excess of allowances compared to actual emission levels.[57] A fixed number of allowances to emit CO_2 are sold in quarterly auctions—each allowance represents a permit to emit one short ton.[58] Allowances may also be bought through secondary exchanges or obtained through offsets, which are GHG emission reductions achieved outside the power sector.[59] The March 2014 clearing price for an allowance was four dollars.[60] Although that price may increase as the cap begins to decrease in 2015, it is much lower than the central federal interagency estimate of the social cost of carbon.[61]

The other cap-and-trade program, California's, encompasses not just CO_2 but other GHG emissions, and applies to importers of electricity into the state as well as power plants in California.[62] The November 2013 auction for 2013

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[52] 26 U.S.C. § 45 (2012).
[53] Steven Ferrey et. al., *Fire and Ice: World Renewable Energy and Carbon Control Mechanisms Confront Constitutional Barriers*, 20 Duke Envtl. L. & Pol'y F. 125, 135 (2010).
[54] *Renewable Electricity Production Tax Credit (PTC)*, Database of State Incentives for Renewables & Efficiency, http://perma.cc/B52A-9QLG.
[55] *Welcome*, Regional Greenhouse Gas Initiative, http://perma.cc/85PL-B9S5.
[56] *Regulated Sources,* Regional Greenhouse Gas Initiative, http://perma.cc/46V2-Q2BA.
[57] Regional Greenhouse Gas Initiative, RGGI 2012 Program Review: Summary of Recommendations to Accompany Model Rule Amendments 1–2, *available at* http://perma.cc/B8LB-2VW3.
[58] *Id.* at 2.
[59] *Id.*
[60] *Auction Results*, Regional Greenhouse Gas Initiative, http://perma.cc/GX9S-TN82.
[61] Four dollars per short ton equals $3.63 per metric ton. The interagency estimate for the social cost of one metric ton of CO_2 emitted in 2015, by comparison, is thirty-eight dollars in 2007 dollars, or $42.69 in 2013 dollars. 2013 Social Cost of Carbon, *supra* note 25, at 3.
[62] Cal. Code Regs. tit. 17, §§ 95810–11 (2014).

allowances produced a market price of $11.48 per allowance,[63] defined as an authorization to emit one metric ton of CO_2 equivalent[64]—significantly less than the central federal interagency price.

b. RPSs and Other Mechanisms

A renewable portfolio standard ("RPS") requires electricity suppliers to procure a certain percentage of their electricity from renewable sources or purchase renewable energy credits from other sources to meet the prescribed standard.[65] RPSs are "focused primarily on increasing the mix of renewable sources of electricity."[66] They subsidize and favor clean energy but do not directly internalize the costs of emissions from generation. As of 2010, thirty states and the District of Columbia had implemented an RPS at some level.[67]

States have also implemented tax credits and other policies to subsidize clean energy.[68] Notably for our purposes, some public utility commissions (the state bodies responsible for economic regulation of electric utilities) are taking proactive measures to reduce GHG emissions and otherwise address climate change.[69] A substantial literature has developed analyzing the effectiveness of RPSs and other subsidizing policies with cap and trade schemes and emissions taxes.[70] Because of the complexity and variety of the states' programs, it is difficult to draw precise general conclusions about their cumulative impact. But the lack of robust direct internalization of environmental costs through mechanisms like taxes and cap and trade programs, combined with the modest nature of many of the other programs, suggests that much more needs to be done to achieve the proper incentives.

Even if all of these federal and state programs are sustained legally, the GHG emissions standards incorporated in them represent only a modest step toward the emissions reductions necessary for the U.S. electricity industry to

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[63] AIR RES. BD., CAL. ENVTL. PROTECTION AGENCY, CALIFORNIA AIR RESOURCES BOARD QUARTERLY AUCTION 5: NOVEMBER 2013 1 (2013), *available at* http://perma.cc/Y8PA-27KN.
[64] CAL. CODE REGS. tit. 17, § 95802(a)(8) (2014).
[65] Joshua P. Ferhsee, *Renewable Mandates and Goals*, *in* THE LAW OF CLEAN ENERGY 77, 77 (Michael B. Gerrard ed., 2011).
[66] *Id.* at 78.
[67] *Id.* at 80.
[68] For an overview of all fifty states' laws relating to energy efficiency and renewable energy, see *State Actions on Clean Energy: A Fifty-State Survey*, *in* THE LAW OF CLEAN ENERGY, *supra* note 64, at 559–618); *see also* DATABASE OF STATE INCENTIVES FOR RENEWABLES & EFFICIENCY, http://perma.cc/56N7-3NUC.
[69] *See, e.g.*, CAL. PUB. UTIL. COMM'N ET AL., WEST COAST PUBLIC UTILITY COMMISSIONS' JOINT ACTION FRAMEWORK ON CLIMATE CHANGE (2006), *available at* http://perma.cc/Q886-YJ44; *Emerging Procurement Strategies*, CAL. PUB. UTILS. COMM'N, http://perma.cc/566J-SWC7. The New York State Public Service Commission recently adopted two orders describing measures that the state's utilities should consider and that it intends to pursue relating to the impact of global warming on its utilities and reduction of greenhouse gases. *See Re* Energy Efficiency Portfolio Standard, Case 07-M-0548, 2013 WL 6858914, at *10–12 (N.Y.P.S.C. Dec. 26, 2013); *Re* Consolidated Edison Company of New York, Case 13-E-0030 et. al., 2014 WL 794789, at 30, 33–35 (N.Y.P.S.C. Feb. 21, 2014). EDF was a party to the latter proceeding.
[70] *See*, *e.g.*, Gesine Bökenkamp et al., *Policy Instruments*, *in* THE SOCIAL COST OF ELECTRICITY 185–230 (Anil Markandya et al. eds., 2010).

adequately address its contribution to global warming.[71] This reality suggests that economic regulators of the industry—i.e., FERC at the federal level—should think creatively about what their role should be. Moreover, as we will explore, even if more powerful regulations along these lines are implemented in the future, there may still be an important role for FERC to play by adopting an environmentally inclusive approach, thanks to its unique jurisdiction and expertise.

II. FERC and the Electricity Industry: Some Background

A. The Early Structure of the Electricity Industry; The Origins of FERC and the FPA

When the FPA was passed in 1935, "the electricity utility consisted mostly of vertically integrated utilities that functioned as traditional regulated monopolies."[72] Vertical integration meant that the same utility would generate electricity, transmit it over high-voltage transmission lines, and distribute it over lower-voltage distribution lines to the consumers in the utility's service area. The utility had a local monopoly and was subject to extensive regulation. Regulators set rates based on the utility's cost of service, including its operating expenses and cost of capital.[73] The industry was dominated by a small number of companies and characterized by inflated rates.[74]

The immediate cause of the FPA's enactment was a Supreme Court decision holding that state regulation of interstate sales of electricity at wholesale violated the Constitution's Commerce Clause[75]—a decision that left a regulatory void now known as the "Attleboro gap."[76] Congress had already created the Federal Power Commission ("FPC") as an independent agency in 1920, charging it with oversight of hydroelectric power.[77] The FPA (of 1935) gave the FPC jurisdiction over wholesale sales—defined as sales for resale[78]—and transmission of electricity in interstate commerce.[79] The statute sought to strike a balance between federal and state regulation, excluding from FPC jurisdiction facilities used for the generation of electric energy, facilities used in local distribution or only for the transmission of electric energy in intrastate commerce,

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[71] *See* Nat'l Research Council, Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia 21 (2011), *available at* http://perma.cc/NA28-CXE5 (stating that "stabilization of [atmospheric] carbon dioxide concentrations at any selected target level would require reductions in total emissions of at least eighty percent (relative to any peak emission level)").
[72] James H. McGrew, FERC: Federal Energy Regulatory Commission 151 (2d ed. 2009).
[73] Michael E. Small, A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers 31 (3d ed. 1994).
[74] McGrew, *supra* note 72, at 139.
[75] Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83, 89–90 (1927).
[76] McGrew, *supra* note 72, at 140.
[77] *Id.* at 5.
[78] 16 U.S.C. § 824(d) (2012).
[79] 16 U.S.C. § 824(a) (2012).

and facilities for the transmission of electric energy consumed wholly by the transmitter.[80] It also excluded government entities and rural electric cooperatives from the FPC's reach.[81]

B. Industry Restructuring

For several decades, the FPC steadily regulated wholesale rates under the traditional cost-of-service approach. Utilities were able to achieve increasing economies of scale by building larger and larger power plants,[82] and the traditional industry structure prevailed until the 1970s. But a number of factors, particularly the energy crisis, converged to launch an industry upheaval in the seventies.[83] Smaller power plants became more economical than the largest plants, and longer-distance transmission became more economical. With incentives from the Public Utility Regulatory Policies Act,[84] which amended the FPA to encourage smaller-scale and renewable generation by non-utilities, generation by independent sources unaffiliated with the utilities became increasingly common.[85] Congress reorganized the FPC as FERC in 1977, making it a branch of the Department of Energy but preserving its status as an independent agency.[86] In the 1980s, FERC adopted a new policy of allowing market forces to determine rates in electricity markets that the agency deemed competitive enough to prevent providers of generation or transmission from raising rates to supracompetitive levels[87]—a change that would have a major impact on the industry's structure.

FERC has since continued its restructuring efforts. In Order No. 888, FERC concluded that discrimination by traditional utilities with control over transmission lines against others seeking access to transmission was hindering development and deployment of independent generation and hindering competition.[88] In response, FERC required all transmission providers under its jurisdiction to provide nondiscriminatory open access tariffs for their transmission facilities.[89] In Order No. 2000,[90] FERC encouraged and set out guidelines for the formation of Regional Transmission Organizations ("RTOs"), independent entities formed by transmission owners in a region to operate their collective transmission networks in a centralized, coordinated, efficient, and open way.

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[80] 16 U.S.C. § 824(b)(1) (2012).
[81] 16 U.S.C. § 824(f) (2012).
[82] Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg 21,540, 21,543 (May 10, 1996) (to be codified at 18 C.F.R. pts. 35, 385) [hereinafter Order No. 888].
[83] McGrew, *supra* note 72, at 144.
[84] Pub. L. No. 95–617, 92 Stat. 3117 (1978).
[85] *See* Order No. 888, *supra* note 82, at 21,545.
[86] McGrew, *supra* note 72, at 5.
[87] Order No. 888, *supra* note 82, at 21,545–56.
[88] *Id.* at 21,550.
[89] *Id.* at 21,541.
[90] Order No. 2000, Regional Transmission Organizations, 89 FERC ¶ 61,285 (Dec. 20, 1999) [hereinafter Order No. 2000].

Today, much of the U.S. electricity grid operates under the supervision of an RTO or an Independent System Operator ("ISO"), a similar type of entity.[91]

Other rulemakings restructuring aspects of the industry have followed. Particularly notable for the purposes of this Article is Order No. 1000, which, among other things, requires transmission providers to participate in a regional transmission planning process that meets certain guidelines and produces a regional transmission plan; requires transmission planning processes to consider transmission needs driven by public policy requirements (federal or state laws such as state renewable portfolio standards); requires some planning and cost allocation coordination by transmission providers in neighboring planning regions; and requires that regional planning processes adopt cost allocation methods, satisfying certain principles, for transmission projects selected for regional cost allocation.[92] FERC issued Order No. 1000 to follow up on earlier reforms it had launched that were aimed at improving regional transmission planning processes,[93] whereby transmission owners and other stakeholders in a transmission region develop and settle on plans for transmission construction and improvement, as well as non-transmission alternatives for meeting energy needs, such as energy efficiency programs, in their region, and how to allocate costs for these projects. Cost allocation of new transmission projects has become a thorny issue, subject to extensive disagreement and litigation, holding up needed expansion and development of the nation's transmission system.[94] Utilities and their customers often cannot agree with other utilities and their customers on how to allocate the costs for large new transmission projects that may cut across multiple transmission owners' service areas, even multiple states, when these projects may provide different levels of different types of benefits[95] to

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[91] *See Regional Transmission Organizations (RTO)/ Independent System Operators (ISO)*, FERC, http://perma.cc/5RN9-36DB (map of RTO/ISO regions).

[92] Fed. Energy Regulatory Comm'n, Order No. 1000 Fact Sheet, *available at* http://perma.cc/D8NY-7NZ5.

[93] *See, e.g.*, Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12,266 (Mar. 15, 2007) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 890].

[94] *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49,842, 49,850–52 (Aug. 11, 2011) (to be codified at 18 C.F.R. pts. 35, 38) [hereinafter Order No. 1000]; *see also* Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 472 (7th Cir. 2009) (litigation over cost allocation).

[95] The two main types of traditionally recognized benefits are benefits from increased reliability of the system and benefits from cheaper electricity or service. But Order No. 1000 states that regional and interregional transmission planning processes also may consider as a benefit fulfillment of "public policy requirements"—for example, state laws mandating that utilities derive a certain percentage of the electricity they provide in the state from renewables. Order No. 1000, *supra* note 94, at 49,937. This type of benefit is particularly contentious since the states have widely varying public policy requirements. A concern of some is that customers will be allocated costs based on benefits that they may not receive or their state may not recognize, such as reducing GHG emissions. *See id.* at 49,879. FERC's response is that the planning process must still adhere to the principle that "the costs of new transmission facilities allocated within the planning region must be allocated within the region in a manner that is at least roughly commensurate with estimated benefits." *Id.*

various customers.[96] The needed expansion and development of transmission, in turn, are due to a number of factors, including a shift (largely driven by state laws) toward renewable energy in the generation mix, and FERC's policy of encouraging wholesale power markets.[97]

FERC has also issued regulations to remedy practices of transmission providers that were having a discriminatory impact on small and variable energy sources such as wind and solar,[98] and to ensure adequate compensation for demand response in energy markets,[99] among other things.[100] FERC has generally grounded the reforms of the electricity industry discussed in this Part in its authority under FPA sections 205 and 206 to ensure that rates, terms, and conditions of interstate wholesale sales and transmission are just and reasonable and not unduly discriminatory or preferential.[101] FERC's reforms have attempted to guide the development of what is a complex patchwork of investor-owned utilities, consumer-owned utilities, and municipality-owned utilities, independent power generators and marketers, conventional generation and renewable generation, and interconnected transmission regions exhibiting various degrees of organization and centralization, all operating within another complex patchwork of federal, state, and local regulation. FERC's overarching goals in these reforms have primarily been twofold: making electricity as cheap as possible and promoting reliability of the nation's electricity system.[102] Although recent reforms such as Orders No. 745, 764, and 1000 suggest that FERC is increasingly concerned with promoting or at least creating a fair playing field for clean energy and energy conservation, FERC has largely ignored and rejected environmental considerations in its regulation of the electricity industry, as we will now discuss.

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[96] For an example of such a disagreement, in this case over a large, high-voltage transmission line that the PJM Interconnection proposed to build to transmit electricity from the Midwest to the East Coast, see *Illinois Commerce Commission*, 576 F.3d 470.

[97] *See* Order No. 1000, *supra* note 94, at 49,849 (discussing need for reform).

[98] *E.g.*, Order No. 764, Integration of Variable Energy Resources, 77 Fed. Reg. 41,482, 41,483 (July 13, 2012) [hereinafter Order No. 764]; Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, 68 Fed. Reg. 49,846 (Aug. 19, 2003) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2003].

[99] Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets, 76 Fed. Reg. 16,658 (2011) [hereinafter Order No. 745]. Demand response is the "reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy." *Id.* at 16,659 n.2. In May 2014, the Court of Appeals for the District of Columbia Circuit vacated Order No. 745 in a 2-1 ruling, finding it an impermissible regulation of retail rates. Elec. Pwr. Supply Ass'n v. FERC, No. 11-1486, slip op. at 14, 16 (D.C. Cir. May 23, 2014).

[100] For a list of FERC's major orders and regulations, see http://perma.cc/TR62-7LHC.

[101] *See, e.g.*, Order No. 764, *supra* note 98, at 41,488; Order No. 745, *supra* note 99, at 16,676; Order No. 1000, *supra* note 94, at 49,890–917; Order No. 890, *supra* note 93, at 12,273; Order No. 888, *supra* note 82, at 21,541.

[102] *See, e.g.*, Order No. 2003, *supra* note 98, at 49,847 (focusing on attaining "reasonably priced and reliable service").

III. FERC's Environmental Policy with Respect to Rate Regulation

FERC's approach to environmental considerations varies across its jurisdictional domains. Compared to its more general regulation of the electricity industry under Part II of the FPA, FERC's more specialized regulation of hydroelectric facilities under Part I of the FPA involves extensive consideration of environmental issues.[103] Congress initially gave the FPC wide-ranging permitting authority over hydroelectric facilities[104] and instructed it to consider recreational purposes among other factors in the permitting process.[105] In 1986, Congress added stronger, more explicit environmental protections.[106] FERC also engages in significant environmental regulation in its oversight of natural gas pipelines, normally requiring environmental impact statements for proposed pipelines and other proposed facilities over which it has jurisdiction.[107]

FERC's historical stance toward environmental issues associated with electricity transmission and wholesale sales is a different story.[108] Through FERC and judicial precedent, environmental considerations have been almost entirely excluded from FERC's administration of sections 205 and 206 of the FPA, the crucial provisions that give FERC its broad responsibility to ensure that the rates, contracts, regulations, and practices, relating to transmission and wholesale sales are "just and reasonable." This Part examines the development of FERC's position, beginning with an important Supreme Court case and then further elaborated in a series of actions by FERC relating to the Commission's responsibilities under NEPA.

A. Hope Natural Gas*: The Investor/Consumer Interest Framework*

In *Federal Power Commission v. Hope Natural Gas Co.*,[109] the Supreme Court established that the fixing of just and reasonable rates under provisions of the Natural Gas Act ("NGA") parallel to those in the Federal Power Act "involves a balancing of the consumer and investor interests."[110] The case concerned an order by the FPC regarding rates collected by Hope, a natural gas producer and marketer based in West Virginia selling to wholesale customers in

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[103] The FPC's broad environmental obligations with respect to hydropower permitting were at issue in—and strengthened by—the landmark litigation over a proposed hydropower facility at Storm King Mountain in upstate New York. *See* Scenic Hudson Pres. Conference v. Fed. Power Comm'n, 354 F.2d 608 (2d Cir. 1965).

[104] *See, e.g.*, 16 U.S.C. § 797 (2005) (granting FERC authority over the development of water power and resources).

[105] 16 U.S.C. § 803 (1992).

[106] Electric Consumers Protection Act of 1986, Pub. L. No. 99-495, 100 Stat. 1243 (codified principally at 16 U.S.C. §§ 797(e), 803(a)(1), 803(j)).

[107] Regulations Implementing the National Environmental Policy Act, 18 C.F.R. § 380.6(a) (2012) (listing FERC actions that generally require an Environmental Impact Statement ("EIS")).

[108] It may be worth noting here that *The Washington Post* has described FERC as "long . . . dominated by oil and gas or utility lawyers." Mufson, *supra* note 14.

[109] 320 U.S. 591, 603 (1944).

[110] *Id.* at 603.

Ohio and Pennsylvania.[111] The FPC had issued its order following complaints by two Ohio cities and the Public Utility Commission of Pennsylvania that Hope's rates were excessive and unreasonable.[112] Most relevant for our purposes are the arguments made by the state of West Virginia, which had intervened and sought its own accounting methods that would produce higher rates.[113] It did so because one component of the rate decision was how to value Hope's gas reserves, a determination that would apply to other gas reserves in the state, affecting property taxes and investment incentives.[114] West Virginia specifically argued, among other things, that the Commission's chosen rate was too low given that the state's gas deposits were diminishing and increasing in value as a consequence.[115]

The Court, in an opinion by Justice Douglas, upheld the FPC's order.[116] The FPC was not bound to use any particular formula, the Court said; rather, it was entitled to deference and discretion.[117] Moreover, it is not the methodology or "theory" but the result or "impact" of the rate order that is to be judged.[118] The considerations raised by West Virginia were beyond the scope of the FPC's mandate. The NGA was inconsistent with the notion that "the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it."[119] Rather, the statute was "plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies."[120] The majority also rejected the argument that the Commission had erred in failing to reduce a discrepancy that existed between industrial and domestic rates, saying, "we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage re-sales for industrial use."[121]

Three Justices dissented,[122] including Justices Frankfurter and Jackson, who both took a broader view of the FPA's public interest duties than the majority. Frankfurter argued that "[the statute's] very foundation is the 'public interest,' and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted."[123] He went on to argue that the case should be remanded to the FPC for it to, among other things, "determine the public interest that is in

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[111] *Id.* at 593–94.
[112] *Id.*
[113] *Id.* at 607–10.
[114] *Id.* at 607–09.
[115] *Id.* at 608.
[116] *Id.* at 594, 619.
[117] *See id.* at 602.
[118] *Id.*
[119] *Id.* at 612.
[120] *Id.*
[121] *Id.* at 616.
[122] *Id.* at 620 (Reed, J., dissenting), 624 (Frankfurter, J., dissenting), 628 (Jackson, J., dissenting).
[123] *Id.* at 627 (Frankfurter, J., dissenting).

its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON."[124]

Jackson argued that the scarce nature of natural gas and the unique characteristics of the industry called for a departure from the Court's traditional utility regulation principles. The investor-interest/consumer-interest model sufficed

> in dealing with railroads or utilities supplying manufactured gas, electric power . . . where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations.[125]

Jackson was largely concerned with the higher prices residential customers were paying compared to industrial customers, believing the discrepancy to reflect undue discrimination and the lower rates to be "hastening decline."[126] He noted the FPC's jurisdictional inability to regulate directly the rates that local gas distribution companies charge to consumers, but he argued the FPC should address the residential-industrial discrepancy by indirectly regulating these rates: "It is too late in the day," he wrote, "to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection."[127] Ultimately, Jackson concluded that the FPC had discretion to adopt its own judgment of what the public interest entails, but he pointedly remarked that the case, if remanded to the Commission, would offer "an unprecedented opportunity if [the FPC] will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy."[128]

The majority's approach in *Hope* has influenced subsequent FERC practice as well as judicial interpretation of the FPA. The D.C. Circuit cited the case in *Grand Council of Crees (of Quebec) v. FERC*,[129] where the Grand Council, a political and governmental entity representing the indigenous Crees of Quebec, and conservationists challenged FERC's decision to permit a seller of hydroelectric power to sell at market-based rates.[130] The petitioners argued that FERC's decision would lead to greater output of hydropower and possibly the construction of new hydro plants, threatening fish and wildlife on which the

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[124] *Id.* at 628.
[125] *Id.* at 656–57.
[126] *Id.* at 635–37, 639.
[127] *Id.* at 660.
[128] *Id.*
[129] 198 F.3d 950 (D.C. Cir. 2000).
[130] *Id.* at 953.

Crees relied for their livelihood, as well as migratory birds.[131] The court held that the groups lacked prudential standing to challenge the decision under the FPA.[132] Citing *Hope*'s principle that ratemaking under the FPA involves balancing the investor and the consumer interests, as well as FERC's own subsequent precedent to this effect, the court characterized the FPA as entirely motivated by antitrust concerns and concluded that environmental considerations were not a part of FPA rate regulation.[133] Such considerations, the court said, without further explanation, "would seem to complicate an already complex process, with little or no offsetting benefit to the public."[134] Moreover, the court held that the groups lacked standing even under NEPA, because NEPA "merely serves to ensure that FERC consider those environmental concerns that it is already authorized to consider"—and given the Court's interpretation of the FPA, "NEPA's procedural requirements do not further petitioners' environmental interests in this instance."[135]

Yet it is possible to imagine Frankfurter and Jackson's approach serving as the basis for a reconceptualization of FERC's role and environmental responsibilities today. Although their views were predicated on a notion that gas regulation should differ from traditional utility regulation because of the scarce and physical nature of the commodity, one could argue that the problem of climate change presents a similar situation, in that failure to take the environmental costs of GHG emissions from electricity generation threatens the interests of persons beyond the immediate investor in and consumer of electricity, including future generations of people. By excluding these considerations from its regulation of the electricity industry and rates in particular, FERC could be said to be perpetuating a system whereby "producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest."[136]

B. NEPA

As the *Crees* opinion noted, FERC's own precedent has excluded environmental considerations from its conception of just and reasonable rates. FERC's treatment of NEPA has been an important part of this approach. The most significant precedent in this regard is a 1987 FERC decision to approve a set of interrelated contracts for the sale of energy and capacity by the Ohio Edison Company and Pennsylvania Power Company (collectively, "the OE system")

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[131] *Id.* at 954.
[132] *Id.* at 995.
[133] *Id.* at 957–58. Interestingly, this characterization is at odds with the Supreme Court's statement in *NAACP v. FPC* that antitrust regulation represented only a "subsidiary" purpose of the FPA. 425 U.S. 662, 670 n.6 (1976).
[134] 198 F.3d at 958.
[135] *Id.* at 959. For a critique of the court's standing rulings, see Mark Seidenfeld & William S. Jordan III, *Judicial Review*, Dev. Admin. L. & Reg. Prac. 89, 102–04 (1999–2000) (calling the holding with respect to the FPA "questionable" and the holding with respect to NEPA "absurd" and "a misreading of NEPA case law").
[136] FPC v. Hope Natural Gas Co., 320 U.S. 591, 657 (1944) (Jackson, J., dissenting).

to the Potomac Electric Power Company ("PEPCO").[137] The Natural Resources Defense Council ("NRDC") challenged FERC's decision, arguing that FERC should have undertaken an environmental impact statement under NEPA before approving the contracts, because the electricity would allegedly come from dirty coal plants that had been grandfathered in under the Clean Air Act, such that the deal would allegedly lead to increased emissions of sulfur dioxide from these plants.[138] FERC concluded it had no such duty, or even authority. Its reasoning was that the approval of a rate filing under the FPA is not an action that affects the environment within the meaning of NEPA:

> Major federal "actions," within the meaning of NEPA, are defined in 40 C.F.R. § 1508.18 as actions with environmental "effects" that are actually or "potentially subject to federal control or responsibility." . . . Because jurisdiction over the siting, construction, licensing and operations of the OE system plants, as well as jurisdiction to order PEPCO to adopt conservation measures, to build new capacity, or to purchase power from other suppliers, have been withheld from this Commission by section 201 of the Federal Power Act, we conclude that neither the environmental consequences of, nor the alternatives to, the proposed sale are potentially subject to the control and responsibility of this agency. . . . Given this jurisdictional constraint on its ability to oversee the siting and construction of these power plants, the Commission has no means by which to assure that their location and technical features pose the least risk of adverse environmental impact. In short, by the time a rate schedule is filed that would involve power production by these plants, the Commission takes these plants as it finds them, environmentally speaking.[139]

FERC's reasoning depends on the premise that the FPA's withholding of jurisdiction over generation facilities should be construed to limit FERC's rate authority in this way. But, as we will explore in Part IV, it may be plausible to view FERC's rate authority as sufficiently independent and plenary that the withholding of jurisdiction over these other matters should not preclude consideration of environmental costs within rate oversight. Under the latter view, FERC would still lack authority to regulate the siting, construction, licensing, and operations of plants. It would still, in short, have to take power plants "as it finds them." But that would not prevent it from factoring environmental costs into rate oversight.[140]

FERC also argued that the Clean Air Act's grandfathering provisions represented a legislative judgment, with which FERC should presumably not inter-

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[137] Monongahela Power Co., 39 FERC ¶ 61,350 (1987).
[138] *Id.* at 62,092–93.
[139] *Id.* at 62,097.
[140] FERC's restrictive view of its authority to take environmental considerations into account may reflect, in part, the heavy-handed remedies NRDC sought, including "requiring PEPCO to adopt conservation measures, to build new capacity, or to purchase power from alternative suppliers." *Id.* at 62,097–98.

fere, to "permit" these types of plants "to continue to operate, notwithstanding environmental hazards they may pose relative to newer plants." Yet factoring in the environmental costs of the proposed arrangement would, arguably, not require FERC to interfere with this judgment. As we will explore in Part V, it is possible to imagine mechanisms whereby FERC could address and reduce environmental hazards while allowing plants like these to continue to operate. By doing so, FERC would not be exercising a veto over the Clean Air Act. FERC would simply be complementing the regulation applying to these plants,[141] and reserving the right to adjust the proposed rate appropriately. Such regulation might influence, but would not necessarily determine, the plant's fate.

One could argue that, for various reasons (examined in Parts IV and V), it would be unwise or inappropriate for FERC to adopt this course, but FERC did not argue this. In light of the very real benefits that considering environmental factors could produce, FERC's reasoning is unpersuasive.

FERC codified its position in its regulations implementing NEPA by establishing a categorical exclusion for electric rate filings submitted under sections 205 and 206 of the FPA from the need for Environmental Impact Statements ("EIS") and Environmental Assessments ("EA").[142] Under the Council on Environmental Quality's ("CEQ") regulations implementing NEPA, agencies may, through appropriate procedure, categorically exclude from the need for an EIS or EA categories of actions "which do not individually or cumulatively have a significant effect on the human environment."[143] In adopting its final rule implementing NEPA, FERC rejected the argument that electric rate filings should not be categorically excluded, simply explaining that it was adopting and codifying its position in *Monongahela*.[144]

FERC made a more thorough case for its policy regarding environmental considerations in the course of a dispute with EPA over FERC's NEPA duties as they applied to Order No. 888. FERC initially concluded that no EIS or EA was necessary because the regulation fell within the categorical exclusion for electric rate filings.[145] But it undertook an EIS at the request of several commenters, including EPA, who were concerned that promoting competition among generators could lead to an increase in harmful emissions, especially nitrogen oxides.[146]

Although it concluded that the order "will affect air quality slightly, if at all, and that the environmental impacts are as likely to be beneficial as negative,"[147] FERC resisted on alternative grounds calls for it to adopt mitigation

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[141] One could perhaps view the new layer as permissible regulation complementing regulation under the Clean Air Act.
[142] 18 C.F.R. § 380.4.
[143] 40 C.F.R. § 1508.4.
[144] Regulations Implementing National Environmental Policy Act of 1969, 52 Fed. Reg. 47,897, 47,900 (Dec. 17, 1987) (to be codified at 18 C.F.R. pts. 2, 157, 380).
[145] Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities, 60 Fed. Reg. 17,662, 17,721 (proposed Apr. 7, 1995).
[146] Order No. 888, *supra* note 82, at 21,670.
[147] *Id.* at 21,672.

measures.[148] Primarily, it asserted that it lacked the legal authority to adopt mitigation measures.[149] FERC characterized itself as "in essence and by law, [an] economic regulator[ ]."[150] FERC argued that the FPA excluded "the physical aspects of generation and transmission" from its jurisdiction, and stated that the agency's actions

> must derive from and advance our statutory mandate to protect consumers by establishing utility rates and business practices that are just, reasonable, and not unduly discriminatory or preferential. These authorities, however broad they are with respect to economic matters, are not unbounded; they may not be used to "fill in the gaps" of regulatory programs that, by law, are not our own.[151]

FERC elaborated by explaining its view that Parts II and III of the FPA

> do not grant the Commission authority to regulate the environmental aspects of jurisdictional activities. . . . The Commission's jurisdiction over generation extends only to matters directly related to the economic aspects of transactions resulting from such facilities.[152]

FERC characterized this jurisdictional limitation as stemming "from the historical purposes for which the Commission was established," which FERC said were twofold: (1) closing the "Attleboro gap" and (2) eliminating economic abuses that were prevalent when the FPA was enacted.[153] FERC went on to reject the notion that its mandate to regulate in the public interest gave it the sought-after environmental authority. The Commission compared the argument to the one rejected by the Supreme Court in *NAACP v. FPC* that the FPA's "public interest" language gave the FPC the authority to prohibit racially discriminatory employment practices by entities subject to its jurisdiction.[154]

FERC also argued that it was not feasible for it to adopt mitigation measures, claiming that it lacked the expertise to address technical aspects of the problem, such as determining a proper baseline for NO_x emissions or establishing whether emissions from a given plant contribute to ozone problems in remote locations.[155] EPA had the jurisdiction and expertise to address such issues, FERC said.[156] FERC noted that proposals that would have FERC attempt to sort out generation used for wholesale transactions versus retail transactions failed to recognize the difficulty, if not impossibility, of this task.[157] Here, notably, FERC added a different type of argument against such proposals, arguing that they would conflict with FERC's own goals in Order No. 888—goals consistent

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[148] *Id.*
[149] *Id.*
[150] *Id.*
[151] *Id.*
[152] *Id.* at 21,683.
[153] *Id.*
[154] *Id.* (citing 520 F.2d 432 (D.C. Cir. 1975), *aff'd,* 425 U.S. 662 (1976)).
[155] *Id.* at 21,672.
[156] *Id.*
[157] *Id.* at 21,673.

with the Energy Policy Act of 1992—"to eliminate time-consuming, inefficient transaction-based approvals that impede open access and to promote entry of sellers into bulk power markets on a competitive basis."[158] FERC was essentially recognizing the inherent tension between the role of economic regulator that the agency has assumed and the demands of environmental regulation of the electricity industry.

FERC further argued that for it to adopt mitigation measures might undercut the regulatory scheme of the Clean Air Act.[159] Here, FERC argued that the commenters' proposals would require the Commission to rework Congress's decisions to grandfather in the dirty coal plants, decisions that "were at the heart of the 1990 Clean Air Act compromise."[160] Outside the means provided by the Clean Air Act, FERC argued, only Congress could address the issue.[161] FERC finally claimed that for it to adopt mitigation measures, which would be limited to addressing emissions due to Order No. 888's reforms, would detract from efforts, some already underway, to solve the NO_x emissions problem by other, more comprehensive means, such as an EPA-administered cap and trade program.[162]

Following the issuance of Order No. 888, EPA referred the order to the Council on Environmental Quality, taking issue with some of the assumptions FERC made in assessing the order's likely environmental impacts, and also suggesting that FERC should contribute to mitigation efforts if efforts under the Clean Air Act and Ozone Transport Assessment Group proved inadequate.[163] Intriguingly, FERC committed to further examining, in such an event (or if EPA undertook a Federal Implementation Plan), "what mitigation might be permissible and appropriate under the Federal Power Act."[164] FERC appears not to have undertaken this inquiry, despite the persistence of NO_x problems and the issuance by EPA of Federal Implementation Plans for NO_x in 2011.[165]

The positions FERC took in *Monongahela* and Order No. 888 remain the agency's positions today. In 2000, the D.C. Circuit affirmed these positions in its *Crees* decision.[166] In the next Part of this Article, we will address and challenge most of these arguments.

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[158] *Id.*
[159] *Id.*
[160] *Id.*
[161] *Id.*
[162] *Id.* at 21,672.
[163] Order Responding to Referral to Council on Environmental Quality, 75 FERC ¶ 61,208, ¶¶ 61,688–89 (1996).
[164] *Id.* at ¶ 61,692.
[165] *See* Brief for the Federal Petitioners 5–13, EPA v. EME Homer City Generation, L.P., No. 12-1182 (S. Ct. argued Dec. 10, 2013).
[166] Grand Council of Crees (of Quebec) v. FERC, 198 F.3d 950, 956–57 (D.C. Cir. 2000).

IV. Toward Greener FERC Rate Regulation: A Statutory Argument

Having laid out FERC's position, we now set forth an argument in favor of a different policy. The broad strokes of this argument are as follows. Contrary to FERC's position, Congress has not clearly stated whether FERC may consider environmental factors in its rate regulation. Given this ambiguity, it would be permissible for FERC to change its policy, interpreting the Act as allowing it to consider environmental factors, and substantively incorporating environmental costs and benefits into its regulation. Moreover, if the FPA were interpreted to give FERC this authority, the reasoning behind FERC's categorical exclusion of its rate regulation from NEPA would no longer hold. NEPA would "kick in" and require FERC to consider the environmental consequences of its actions in this context. Although it might seem counterintuitive to argue that the agency should bind itself in this way, we hope to show how the result might be preferable as a matter of regulatory policy, including as a means for FERC to advance its own goals.

A. *FERC's Authority: An Ambiguous Matter?*

The Supreme Court established the framework for assessing agency interpretations of statutes in *Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc.*[167] First we must ask "whether Congress has directly spoken to the precise question at issue. If the intent of Congress is clear . . . the agency . . . must give effect to the unambiguously expressed intent of Congress."[168] In determining whether Congress has specifically addressed the question at issue, we must consider the statutory provisions at issue in the context of the overall statutory scheme.[169] "[T]he meaning of one statute may be affected by other Acts, particularly where Congress has spoken subsequently and more specifically to the topic at hand."[170] If, however, "Congress has not directly addressed the precise question at issue, the question . . . is whether the agency's answer is based on a permissible construction of the statute."[171] A court's prior judicial construction of a statute trumps an agency construction otherwise entitled to *Chevron* deference "only if the prior court decision holds that its construction follows from the unambiguous terms of the statute and thus leaves no room for agency discretion."[172]

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[167] 467 U.S. 837 (1984).
[168] *Id.* at 842–43.
[169] Food & Drug Admin. v. Brown & Williamson Tobacco Corp., 529 U.S. 120, 132–33 (2000).
[170] *Id.* at 133.
[171] *Chevron*, 467 U.S. at 843.
[172] Nat'l Cable & Telecomms. Ass'n v. Brand X Internet Servs., 545 U.S. 967, 982 (2005).

i. The FPA's Text

Three provisions of the FPA are particularly relevant in determining whether Congress addressed the question of whether FERC may consider environmental factors in its rate regulation: sections 201, 205, and 206 (sections 824, 824d, and 824e in the U.S. Code). These provisions do not state, nor arguably even suggest, that FERC should ignore environmental factors in its rate regulation. In fact, taken together, the provisions can plausibly be read as harmonious with consideration of environmental factors.

The declaration of policy in section 201 states that "the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter . . . and of that part of such business which consists of" interstate transmission and wholesale sales in interstate commerce is "necessary in the public interest . . . ."[173] Two things in particular jump out about this language for our purposes—one weighing in favor of, and one perhaps weighing against, an environmentally inclusive reading. In favor is the public orientation of the public interest language, suggesting a compatibility with a regulatory approach that would consider not just the private costs and benefits of electricity sales and transmission, but also their externalities—with environmental externalities being perhaps the most significant of the externalities associated with the electricity industry.[174] Weighing on the opposite side of the scale is the provision's focus on the "business" of transmitting and selling electricity, which arguably supports the type of interpretation the D.C. Circuit reached in the *Crees* case, that the statute is focused on antitrust concerns.[175]

FERC has rejected the view that the public interest language licenses it to consider environmental factors. It compared the argument to one rejected by the Supreme Court, that the same language gave the FPC the authority to prohibit racially discriminatory employment practices by entities subject to its jurisdiction.[176] There, the Court held that the public interest language is not a "broad license to promote the general public welfare. Rather, the words take meaning from the purposes of the regulatory legislation."[177] The main purpose of the legislation, the Court said, was "to encourage the orderly development of plentiful supplies of electricity . . . at reasonable prices."[178] The public interest language was a charge to the same effect, the Court said, noting that "the par-

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[173] 16 U.S.C. § 824(a).
[174] *See* Knee, *supra* note 15, at 764–73 (arguing that environmental costs and benefits are relevant to the principles of cost minimization, nondiscrimination, and adequate service that have informed economic regulation of electric utilities).
[175] *See* Grand Council of Crees (of Quebec) v. FERC, 198 F.3d 950, 957–58 (D.C. Cir. 2000).
[176] Order No. 888, *supra* note 82, at 21,683 (citing 520 F.2d 432 (D.C. Cir. 1975), *aff'd,* 425 U.S. 662 (1976)).
[177] NAACP v. FPC, 425 U.S. 662, 669 (1976).
[178] *Id.* at 669–70. Among the statute's "subsidiary" purposes, the Court said, was the Commission's authority to consider conservation and environmental questions, but here the only FPA provisions the Court cited were ones dealing with hydropower. *See id.* at 670, n.6.

ties point to nothing in the [FPA or the Natural Gas Act] or their legislative histories to indicate that the elimination of employment discrimination was one of the purposes" behind the statutes.[179]

The argument advanced by the NAACP seems distinguishable from the argument that the public interest language supports a claim of authority by FERC to consider environmental factors. The environmental impacts of the electricity industry can more plausibly be viewed as an integral aspect of the "orderly production of plentiful supplies of electric energy . . . at just and reasonable rates."[180] This is in part because of the enormous environmental impacts of the industry, which is a disproportionate polluter compared to other U.S. industries. Another distinguishing factor is the clearer causal relationship that exists between electricity rates and environmental consequences than that between rates and employment practices.[181]

Moving on to sections 205 and 206 (sections 824d and 824e), which grant FERC its specific rate regulation authority, we can see that the language of these provisions, like the language of other New Deal-era organic statutes,[182] is broad in what it subjects to FERC jurisdiction ("all rates and charges . . . for or in connection with . . . and all rules and regulations affecting or pertaining to;" "any rate, charge, or classification; any rule, regulation, practice, or contract affecting such rate, charge, or classification") and vague in the standards it demands ("just," "reasonable," "undue prejudice or disadvantage").[183] The statute does not specify how FERC should give meaning to these standards. Rather, the language leaves the Commission a great amount of discretion and seems capacious enough to allow for consideration of environmental factors.[184]

FERC's rate regulation power is, however, limited to wholesale sales and transmission of electricity in interstate commerce.[185] And section 201 contains further language limiting FERC's jurisdiction. It excludes jurisdiction "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,"[186] and it reserves authority for the states.[187] But

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[179] *Id.* at 670.
[180] *Id.*
[181] For example, a coal power company clearly benefits vis-à-vis a wind power company when GHG costs are not internalized into electricity rates, and electricity consumption and pollution will be higher when electricity is cheaper. By contrast, the effect of discriminatory employment practices on rates, and vice versa, would likely be less clear. *See also* Knee, *supra* note 15, at 764–73.
[182] *E.g.*, 15 U.S.C. §§ 41–58 (FTC Act).
[183] 16 U.S.C. §§ 824d(a)–(b); § 824e(a) (2012).
[184] Contrast this language with the statutory provisions at issue in *Department of Transportation v. Public Citizen*, 541 U.S. 752 (2004). There, the Supreme Court held that the Federal Motor Carrier Safety Administration lacked discretion under its statutory mandate to regulate emissions from motor vehicles. *Id.* at 766–67. The statute directed that "the Secretary of Transportation shall register" persons meeting a set list of specific criteria. *Id.* (quoting 49 U.S.C. § 13902(a) (2006)). The criteria were on the whole much more specific, leaving much less room for discretion, than the "just and reasonable" and "public interest" criteria that FERC must apply.
[185] 16 U.S.C. § 824(b).
[186] 16 U.S.C. § 824(a).

these limitations should be construed as constraining what FERC could do in incorporating environmental considerations, not as clearly precluding FERC from doing so. In the following paragraphs, we elaborate this point in criticizing a crucial argument FERC has made regarding section 201's limiting language and in justification of excluding environmental considerations. We then criticize a second crucial argument FERC has made regarding its rate regulation authority.

1. How Considering Environmental Factors Could Be Consistent with Section 201

FERC has argued that incorporating environmental considerations into rate oversight would *necessarily* be tantamount to exercising authority over siting, construction, licensing, and operation of generation facilities, violating the FPA's withholding of jurisdiction over facilities used for generation.[188] FERC's interpretation of this limiting provision as concerning matters such as siting, construction, licensing, and operation seems reasonable. The rest of FERC's argument, however, is weak.

It is important to distinguish between *authority* and mere *influence* over the siting, construction, licensing, and operation of generation facilities. FERC already exercises considerable influence over what, when, where, and how generation and transmission get built and how they are operated. For FERC to consider environmental factors would only change the nature, and perhaps increase the degree, of its influence over these matters. The D.C. Circuit recognized FERC's influence over such matters in a 2009 case in which it held that FERC had jurisdiction over ISO New England's ("ISO NE") "installed capacity requirement" ("ICR").[189] The ICR represented an estimate of the amount of generation capacity that needed to be maintained in the New England region to meet peak demand and ensure grid reliability.[190] ISO NE used this figure to structure an auction in which generators and other capacity providers submitted bids to provide capacity, with the net effect being that the installed capacity requirement influenced the prices these providers would be paid.[191] The Connecticut Public Utility Commission ("PUC") argued that FERC lacked jurisdiction to review or change the ICR because, it asserted, any increase in the ICR required building more capacity when decisions to build new generation were traditionally left to the states under the FPA.[192] The D.C. Circuit rejected the argument, disagreeing with the premise that ICR increases *required* addi-

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[187] 16 U.S.C. § 824(b). Even though the statute does not similarly withhold jurisdiction from FERC over *inter*state transmission facilities, "[t]he states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of [all] electric transmission facilities." Piedmont Envtl. Council v. FERC, 558 F.3d 304, 310 (4th Cir. 2009). Amendments to the FPA, however, have given FERC certain limited powers to supersede states in this area. *Id.*
[188] *See supra* Part III.
[189] Conn. Dept. of Pub. Util. Control v. FERC, 569 F.3d 477, 479 (D.C. Cir. 2009).
[190] *Id.* at 480.
[191] *Id.*
[192] *Id.* at 481.

tional capacity.[193] Rather, the court explained, state and municipal authorities retained the ultimate right to say what capacity, and what type of capacity, got built.[194] The ICR merely affected incentives to develop generation resources, and FERC, the court explained, could *directly* set the price of capacity precisely to incentivize such development if it wanted to.[195] FERC's review of the ICR was thus not direct regulation of generation facilities in violation of the FPA.[196]

Order No. 1000 is an example of how FERC is increasingly asserting authority to influence matters of siting and licensing of facilities, both transmission and generation.[197] Indeed, in challenging Order No. 1000, utilities are arguing that FERC is impermissibly regulating siting through its oversight of transmission planning processes and its cost allocation reforms.[198] FERC responds that "[w]hile Order No. 1000's planning and cost allocation processes may influence . . . state approvals [of projects selected in regional transmission plans], that is a permissible byproduct of the Commission's legitimate exercise of its authority to regulate interstate transmission."[199] Whether the utilities will prevail on these arguments remains to be seen, but Order No. 1000 shows that FERC is increasingly asserting such influence.[200]

An additional problem with FERC's argument is that it performs a sleight of hand by hiding the fact that environmentally agnostic regulation may have just as much influence over the siting, construction, licensing, and operation of generation as would environmentally conscious regulation. For example, by *not* incorporating GHG externalities into its rate regulation, FERC influences decisions about what generation should be built just as much as it would by *incorporating* these externalities. The effect of its exclusion of the externalities is simply to give GHG-intensive generation, such as coal, an advantage vis-à-vis cleaner energy, such as wind. FERC's argument commits a common fallacy—it ignores how government regulation (in this case, FERC's current approach) already influences the existing state of affairs, and wrongly views the status quo

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[193] *Id.*
[194] *Id.*
[195] *Id.*
[196] *Id.* at 482.
[197] *See supra* Part II.B for description of the order.
[198] *See*, *e.g.*, Order No. 1000, *supra* note 94, at 49,856, 49,906.
[199] Brief of Respondent Fed. Energy Regulatory Comm'n at 24, S.C. Pub. Serv. Auth. v. FERC, Nos. 12-1232, et al. (D.C. Cir., Sept. 25, 2013).
[200] Contrast those actions with an established example of impermissible overreach by FERC. In *Piedmont Environmental Council v. FERC*, the Fourth Circuit held that FERC lacked authority to permit construction of a transmission line in a national interest electric transmission corridor when a state with jurisdiction over the proposed line had affirmatively denied a permit, even though the FPA, pursuant to amendments by the Energy Policy Act of 2005 ("EPAct"), gave FERC power to issue such a permit when the state delayed or failed to act on a permit application. 558 F.3d 304, 313 (4th Cir. 2009). Arguably implicit in the Fourth Circuit's ruling (and the EPAct itself) is the premise that no other part of the FPA grants FERC such affirmative permitting power. *See id.* at 310 ("The states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of electric transmission facilities."). FERC's action in *Piedmont* could thus be seen as a direct and unilateral exercise of authority over the siting, construction, and licensing of a transmission facility, in violation of not just the EPAct provisions but all of its combined statutory authority.

as a neutral baseline not actively shaped by regulation. Although considering environmental factors in this way would entail increased regulation in the sense that it would require more work by FERC and by industry to comply with the regime, it would, in an important sense, not increase FERC's influence over siting, construction, licensing, and operation of generation facilities, but would merely revise the nature and direction of FERC's influence over these matters.

Finally, Supreme Court rulings suggest that FERC's arguments in defense of its current policy may understate the extent of the agency's authority under sections 205 and 206 and overstate the importance of section 201's limitations. In *FPC v. Southern California Edison Co.*,[201] the Court held that FERC's authority under the FPA is plenary vis-à-vis the states unless Congress explicitly states otherwise.[202] The limiting provisions of section 201 must be read alongside the plenary grants of authority in these sections. The Court has also circumscribed the significance of section 201's provision reserving powers for the states, describing it as "a mere policy declaration that cannot nullify a clear and specific grant of jurisdiction [in the FPA], even if the particular grant seems inconsistent with the broadly expressed purpose."[203]

2. *Environmental Considerations As Economic Considerations*

FERC has also interpreted its jurisdiction over generation to "extend[ ] only to matters directly related to the economic aspects of transactions resulting from such facilities."[204] This functional-jurisdictional argument echoes a traditional utility-regulation distinction between private/economic concerns and public/non-economic concerns.[205] The economic/non-economic distinction and FERC's argument invoking it, however, are vulnerable on several grounds. First, in today's dominant regulatory and policy paradigm, the environmental consequences of electricity generation *are* "matters directly related to the economic aspects" of such transactions. The extent of these consequences is largely a function of the prices at which the transactions occur, and the corresponding incentives created. Moreover, the environmental consequences produce real economic costs.[206] Second, the narrowness of FERC's interpretation of its jurisdiction is arguably unwarranted. The FPA charges FERC with ensuring that rates, charges, rules, regulations, classifications, practices, and contracts related to wholesale sales and interstate transmission of electricity are "just and reasonable" and not "unduly discriminatory or preferential" and gives no further guidance as to what these vague standards mean. Thus, FERC's interpretation does not unambiguously follow from the terms of the statute. The legislative history behind the FPA perhaps provides more support for FERC's

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[201] 376 U.S. 205 (1964).
[202] *Id.* at 215–16.
[203] New York v. FERC, 535 U.S. 1, 22 (2002) (internal quotations and citations omitted).
[204] Order No. 888, *supra* note 82, at 21,683.
[205] *See* James J. Hoecker, *The NEPA Mandate and Federal Regulation of the Natural Gas Industry*, 13 ENERGY L.J. 265, 311 n.1 (1992).
[206] FERC seems to have a narrow view of the "economic aspects" of the relevant transactions as being limited to the private cost to the electricity consumer, i.e., as excluding externalities.

position,[207] but FERC's position is weak if it depends so heavily on legislative history, especially if, as we will argue, other factors weigh against its position.

Notably, FERC has interpreted other, closely related parts of the FPA—which seem just as focused on economic considerations as the FPA's rate provisions—not to preclude consideration of environmental factors. Section 203 gives FERC power over mergers by jurisdictional utilities and charges FERC with approving these mergers if it finds that the proposed transaction (A) "will be consistent with the public interest" and (B) will meet certain other economic criteria specified in the statute.[208] Although FERC generally excludes merger review from the need for an environmental assessment or environmental impact statement on the grounds that mergers generally do not produce significant impacts on the environment, it has conducted EAs for proposed mergers in the past when it found they could have significant environmental impacts.[209]

Thus, the text of the FPA should arguably not be interpreted to preclude FERC from incorporating environmental considerations into its rate regulation. Rather, the text could be understood as being ambiguous about whether FERC may incorporate such considerations.

ii. The FPA's Legislative History

FERC may be on its soundest footing when it appeals to the legislative history of the FPA to argue against the notion that it may incorporate environmental considerations into its rate regulation. A review of the legislative history pertaining to the statute's rate provisions reveals no discussion of environmental considerations. FPC Solicitor Dozier DeVane, a drafter of an early version of the bill, summarized Part II of the FPA as having two main objectives: complementing state regulation of rates, and achieving regional coordination of electricity systems.[210] The main rate-related concern of the members of the Senate and House interstate commerce commissions was the possibility that utilities were charging excessive, monopolistic rates to consumers.[211] There is even language supporting *Hope*'s idea that the statute was meant to be limited to balancing the consumer and investor interests.[212] Conservation, when it is brought up, refers primarily to conservation of fossil fuel resources for preventing their waste.[213] None of this is surprising given the very different conceptions of mankind's relationship to the environment that prevailed at the time.

One response to the thrust of this legislative history is that incorporation of environmental considerations actually advances the two purposes that DeVane

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[207] *See infra* Part IV.A.ii.
[208] 16 U.S.C. § 824b (2012).
[209] *E.g.*, *S. Cal. Edison Co. & San Diego Gas & Elec. Co.*, 49 FERC ¶ 61,091, 61,357 (Oct. 27, 1989).
[210] *Public Utility Holding Companies: Hearings Before the Comm. on Interstate and Foreign Commerce on H.R. 5423*, 74th Cong. 549 (1935).
[211] *See id.* at *passim*; *Public Utility Holding Company Act of 1935: Hearings Before the Comm. on Interstate Commerce on S. 1725*, 74th Cong. *passim* (1st Sess. 1935).
[212] *See, e.g.*, *id.* at 252, 264.
[213] *Id.* at 664.

identified, particularly that of achieving regional coordination of electricity systems. For example, renewable energy and reduction of carbon emissions are driving much of the need for new transmission today.[214] Yet states and utilities are having difficulties agreeing on the costs and benefits of these projects, including benefits from compliance with renewable energy mandates, and how to allocate them.[215] One way that Order No. 1000 tries to solve this problem is to mandate consideration of public policy requirementsrequirements largely having to do with clean energy procurement—in regional transmission planning.[216] Thus, in effect, FERC is trying to improve regional coordination of electricity systems by requiring consideration of largely environmentally driven laws. More direct consideration of environmental factors by FERC could streamline and facilitate this coordination process.

A second response is that legislative history should not hinder the flexibility that *Chevron* gives agencies—flexibility that they arguably need—to adapt statutes to changing or particular circumstances.[217] That applies with great force here, since environmental issues are now widely seen as central to the task of developing the electricity industry intelligently and for the future.

iii. What About EPA?

As noted above, the entire U.S. Code is potentially relevant at step one of the *Chevron* inquiry.[218] One argument against interpreting the FPA to give FERC the authority to consider environmental factors in its rate regulation is the argument that Congress has through other legislative actions, such as giving EPA wide-ranging environmental regulatory authority, expressed an intent to preclude this authority from FERC. In *Brown & Williamson*, the Supreme Court held that Congress's actions, taken as a whole, made it clear that it intended to withhold jurisdiction from the FDA to regulate tobacco, ruling against the FDA's arguments that its own statutory mandates gave it authority to regulate the drug.[219]

A problem with this argument, however, is that NEPA has established a strong policy in favor of not just encouraging but requiring all federal agencies

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[214] *See* Order No. 1000, *supra* note 94, at 49,849.
[215] *See id.* at 49,850 (citing a characterization by the Brattle Group), 49,857, 49,921; *see also* Ill. Commerce Comm'n v. FERC, 721 F.3d 764, 773 (7th Cir. 2013).
[216] *See* Order No. 1000, *supra* note 94, at 49,845–46 (summarizing the order's mandate), 49,857 (noting how better regional planning could more cost-effectively integrate renewable energy resources required by public policy requirements).
[217] *Cf.* Cass R. Sunstein, *Justice Scalia's Democratic Formalism*, 107 YALE L.J. 529, 533, 552–53 (1997) (arguing that administrative agencies are more politically accountable and have greater expertise in interpreting and applying their statutes than are courts, and arguing for discretion for agencies to engage in "statutory adaptation"); Freeman & Spence, *supra* note 21 (arguing that "congressional dysfunction invites agencies and courts to do the work of updating statutes," that "agencies are better suited than courts to do that updating work," and that "the case for deferring to agencies in that task is stronger than ever with Congress largely absent from the policymaking process").
[218] Food & Drug Admin. v. Brown & Williamson Tobacco Corp., 529 U.S. 120, 132–33 (2000).
[219] *Id.* at 143–56.

to consider the environmental consequences of their regulatory actions.[220] To compare the situation with that of *Brown & Williamson*, imagine if in that case Congress had passed a landmark law instructing all federal agencies to consider the consequences of their regulatory actions on tobacco consumption and its resulting detriment to public health. Imagine that the law also says that "to the fullest extent possible . . . the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with" a policy of reducing tobacco consumption and promoting public health.[221] Even if some other agency had been specifically and thoroughly (but not exclusively) tasked with regulating tobacco, it would seem contrary to Congress's intent to preclude the FDA from at least considering the consequences of its actions on tobacco consumption, and possibly even substantively regulating tobacco. Although it is true that NEPA's procedural requirements are distinct from a substantive statutory license or mandate to incorporate environmental considerations into an agency's regulation, might not our imaginary tobacco NEPA-parallel have nevertheless given the FDA the boost it needed to tip the 5-4 result in *Brown & Williamson* in its favor? Thus, if we accept the premise that the FPA itself does not preclude FERC from considering environmental factors in its rate regulation, then in light of NEPA, it seems dubious that Congress has otherwise precluded FERC from adopting this policy.

Moreover, FERC could limit its consideration of environmental factors in various ways to lessen the bite of this argument. For example, FERC could limit itself to addressing environmental problems that Congress has not indicated it wishes to be addressed exclusively by other means, or to those that fall within FERC's special institutional competence, or to those that meet both of these conditions. Under such an approach, FERC might want to refrain from internalizing into wholesale electricity rates the environmental costs associated with traditional criteria air pollutants, on the grounds that the CAA arguably

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[220] *See* 42 U.S.C. § 4331 (2006) (stating that "it is the continuing responsibility of the Federal Government . . . to use all practicable means and measures . . . in a manner calculated to foster and promote the general welfare, to create and maintain conditions under which man and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations of Americans" and "to use all practicable means, consistent with other essential considerations of national policy, to improve and coordinate Federal plans, functions, programs, and resources to the end that the Nation may" achieve various environmental goals, including intergenerational equity and "enhanc[ing] the quality of renewable resources"); *see also id.* § 4332 ("[T]o the fullest extent possible: (1) the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this chapter, and (2) all agencies of the Federal Government shall—

> (A) utilize a systematic, interdisciplinary approach which will insure the integrated use of the natural and social sciences and the environmental design arts in planning and in decisionmaking which may have an impact on man's environment;
>
> (B) identify and develop methods and procedures . . . Which will insure that presently unquantified environmental amenities and values may be given appropriate consideration in decisionmaking *along with economic and technical considerations*;"
>
> (C) [perform environmental impact statements for "major Federal actions significantly affecting the quality of the human environment . . . ."]) (emphasis added).

[221] *Cf.* 42 U.S.C. § 4331 (2006).

gives EPA exclusive authority to regulate such air pollutants. It could focus on reforming aspects of the electricity industry over which it has the most, if not exclusive, authority, such as interstate transmission planning and wholesale rate structures, and which have important systemic environmental consequences.[222] Interagency consultation and coordination between FERC and EPA and other environmental regulators could serve as another useful way for FERC to limit its environmental interventions to areas where they would be most helpful.[223] (In Part V we discuss how this type of coordination could significantly improve regulation of the electricity industry.) FERC could expressly announce its intent to adopt such limiting measures in announcing its new policy of taking environmental considerations into account.

iv. The Brand X *Inquiry*

A rule of administrative law laid out in *National Cable & Telecommunications Ass'n v. Brand X Internet Services*[224] dictates that we also consider the way courts have interpreted the relevant provisions of the FPA. *Brand X* held that a court's prior judicial construction of a statute trumps an agency construction otherwise entitled to *Chevron* deference "only if the prior court decision holds that its construction follows from the unambiguous terms of the statute and thus leaves no room for agency discretion."[225] In *Hope Natural Gas*, the Supreme Court interpreted parallel provisions of the Natural Gas Act, setting the foundation for what factors would be deemed proper for FERC to consider in its rate regulation.[226] On the one hand, the Court endorsed a policy of allowing the FPC wide discretion to regulate rates, saying that it was not the methodology or "theory" of the FPC's approach but its result or "impact" that the courts should review.[227] On the other hand, the Court laid out a clear principle that the fixing of "just and reasonable rates" under the NGA "involves a balancing of the consumer and investor interests,"[228] and does not encompass the type of public interest considerations that Justices Jackson and Frankfurter thought the FPA required the Commission to consider, such as the "impoverishment of future generations" through excessively rapid depletion of limited natural gas resources.[229] The D.C. Circuit relied on the *Hope* consumer/investor interest principle in rejecting the argument that FERC should have considered

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[222] The type of consequences we primarily have in mind here is not the immediate land and wildlife impacts of transmission line construction—impacts that are already regulated by other government agencies—but the broader, systemic impacts associated with the different energy mixes made possible by different grid arrangements.
[223] *Cf. generally* Jody Freeman & Jim Rossi, *Agency Coordination in Shared Regulatory Space*, 125 HARV. L. REV. 1131 (2012) (discussing interagency decision-making and its benefits).
[224] 545 U.S. 967 (2005).
[225] *Id.* at 982.
[226] *See supra* Part III.A for a description of the case.
[227] 320 U.S. 591, 602 (1944).
[228] *Id.* at 603.
[229] *Id.* at 656–57 (Jackson, J., dissenting).

the environmental consequences of a decision it made to authorize market-based electricity sales.[230]

There are a number of arguments why *Hope* should not preclude FERC from considering the environmental factors of its rate regulation. First of all, a court's interpretation of an agency statute is binding "only if the prior court decision holds that its construction follows from the unambiguous terms of the statute and thus leaves no room for agency discretion."[231] The point of this rule is to avoid the "ossification of large portions of our statutory law" that would result from "precluding agencies from revising unwise judicial constructions of ambiguous statutes."[232] First, *Hope* was addressing the NGA, and it did not address the specific question of whether the parallel language of that act gave the FPC authority to consider environmental factors. Second, the *Hope* majority did not explicitly state that the NGA was unambiguous on the question of what interests it encompassed. To this effect, it is worth noting that, just one year before *Hope*, the Supreme Court held that the NGA's "requirements of 'just and reasonable' embrace *among other factors* two phases of the public interest: (1) the investor interest; (2) the consumer interest."[233] The Court did not say what these other factors were, but the statement suggests that the NGA, like the FPA, is far from unambiguous about encompassing and protecting only the investor and consumer interests. The FPA's ambiguity on this point is actually highlighted by the D.C. Circuit's much more recent ruling on the FPA in *Crees*. Although the court cited *Hope* in support of its own, similarly narrow reading of the FPA, it also based its holding on deference to FERC's position and a general policy of allowing FERC wide discretion in regulating rates.[234] In doing so, the court invoked *Chevron* and effectively implied that the FPA was silent on the very issue on which *Hope* purported to find the NGA's parallel provisions to have spoken.[235] Third, reducing excessive environmental costs is, arguably, in the interests of consumers and even investors too.[236]

It may also be possible to limit the holding of *Hope* on the grounds that the non-consumer/investor interest that West Virginia was asking the FPC to protect was the state's own, rather narrow economic self-interest. If we are considering whether FERC should have authority to consider the effects of its rate regulation on GHG emissions, for example, then the nation's—indeed, the whole world's—grave interest in preventing or limiting climate change would seem a far more compelling candidate for FERC consideration under the FPA's "public interest" language. *Hope* and its progeny, such as *Crees*, should argua-

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[230] Grand Council of the Crees (of Quebec) v. FERC, 198 F.3d 950, 957–58 (D.C. Cir. 2000); *see also supra* Part III.A.
[231] Nat'l Cable & Telecomms. Ass'n v. Brand X Internet Servs., 545 U.S. 967, 982 (2005).
[232] *Id.* at 983.
[233] Fed. Power Comm'n v. Natural Gas Pipeline Co. of Am., 315 U.S. 575, 606–07 (1942) (emphasis added).
[234] *Grand Council of Crees*, 198 F.3d at 957–58.
[235] *Id.* (citing *Chevron*'s rule about "congressional silence" in the context of settling the FPA question).
[236] *See* Knee, *supra* note 15, at 764–73.

bly not be a barrier to FERC's ability to change course and consider environmental factors in its rate regulation.

B. Room for Change, and a Better Way

If the FPA and other statutes taken together do not clearly preclude FERC from taking environmental considerations into account in its rate regulation, it still must be established that environmentally conscious rate regulation would be reasonable under the FPA,[237] and that FERC could change its long-standing policy without the action being deemed arbitrary and capricious. In *FCC v. Fox Television Stations, Inc.*,[238] the Supreme Court established important principles governing agencies' discretion to change policy positions. The Court rejected the notion that agency action should, under the Administrative Procedure Act,[239] necessarily be subject to a heightened standard of review when the action represents a reversal in policy.[240] The Court explained that the agency must "show that there are good reasons for the new policy. But it need not demonstrate to a court's satisfaction that the reasons for the new policy are *better* than the reasons for the old one . . . ."[241] When, however, an agency's new policy "rests upon factual findings that contradict those which underlay its prior policy . . . [o]r when its prior policy has engendered serious reliance interests that must be taken into account . . . ," the agency must provide a reasoned explanation for "disregarding facts and circumstances that underlay or were engendered by the prior policy."[242]

FCC v. Fox thus generally supports agency discretion in adopting new policy positions and interpretations of statutes they administer, but suggests (in dicta) that agencies do need to provide detailed justifications for policy reversals that rest on factual findings contradicting those that underlay the prior policy or when the prior policy has engendered serious reliance interests. Accordingly, FERC would likely need to provide a reasoned explanation for its turnaround, given that the move would represent a major shift in policy from one that, it would seem, has engendered serious reliance interests on the part of the electricity industry, such as investment in projects under the expectation that FERC would not take these projects' environmental consequences into account in its rate regulation. The reviewing courts would be likely to require "a reasoned explanation . . . for disregarding facts and circumstances that underlay or were engendered by the prior policy."[243]

We now present an argument for how FERC could meet this burden and that of *Chevron* step two. The argument for why our proposal would be a reasonable, indeed superior, interpretation of the statute's language should be

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[237] *See* Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc., 467 U.S. 837, 843 (1984).
[238] 556 U.S. 502 (2009).
[239] 5 U.S.C. §§ 701–706 (2012).
[240] *Fox*, 556 U.S. at 514.
[241] *Id.* at 515–16 (citations omitted).
[242] *Id.* (citations omitted).
[243] *Id.* (citations omitted).

somewhat evident in light of the preceding discussion, but can be summarized succinctly here: If we broadly conceive the public interest that FERC is supposed to serve, FERC-jurisdictional rates would be far more just and reasonable if they did not result in the imposition of excessive environmental costs on society and did not favor GHG-intensive generation over cleaner energy solutions. Moreover, as we will demonstrate, the policy reasons for the agency to take a new course are compelling. Some of the reasons we provide are specific to the unprecedented crisis and challenge of climate change, which FERC could play a valuable role in addressing. But we also offer more general reasons relating to the need to bridge the old-fashioned divide between "economic" and "environmental" energy regulation—a project that could help us address issues other than climate change, including unforeseen energy challenges of the future—and to bring FERC regulation in line with positive federal regulatory trends toward incorporating environmental considerations into regulatory decision-making. Finally, it is relevant that courts have approved radical changes in policy and FPA interpretation by FERC in the past, demonstrating the broad deference granted to FERC.

i. The Benefits of Integrated Environmental-Energy Regulation

Our federal regulatory approach to the electricity industry is fundamentally schizophrenic. Lincoln Davies has described the problem well in the context of discussing the split between environmental law and energy law more broadly:

> It is one of the most important—and unspoken—paradoxes of the modern American regulatory state: Energy law and environmental law rarely, if ever, merge. The fact that energy and environmental law do not work together has massive implications for the nation's future, particularly if we aim to curb our addiction to oil. Suggestions for how to change our energy trajectory are not in short supply. We need a smarter grid, and more of it. We need new transmission rules, and better ways of resolving siting conflicts. We need different transportation technologies, and better incentives for transitioning to them. We need to halt climate change, and move to electricity production that helps us do so. We need to reduce energy demand, and change our behavior to shift that curve. We need more efficiency, and fast. . . . Yet such specific policy reforms, as necessary as they are, do not take into account . . . the disjunction between energy and environmental law.[244]

Davies categorizes the deficiencies that result from the fissure between energy and environmental law as (1) inefficaciousness, (2) inefficiency, (3) foregone

[244] Lincoln L. Davies, *Alternative Energy and the Energy-Environment Disconnect*, 46 IDAHO L. REV. 473, 474–75 (2010).

synergies, and (4) incompleteness.[245] His taxonomy is useful to us, as it captures the deficiencies in FERC's current approach to regulation of the electricity industry.

Inefficaciousness occurs when one area undermines the effectiveness of the other.[246] The conflict between FERC and EPA over Order No. 888 illustrates this phenomenon. EPA was concerned that FERC's open-access transmission reforms would lead to an increase in NO_x emissions, directly undermining efforts to control the emissions. FERC's self-positioning as a purely "economic" regulator often puts the Commission's goals and policies in direct tension with the environmental goals and policies of other regulation.

Inefficiency occurs when the fields advance their objectives, but in a way that is costlier than necessary.[247] An example Davies provides is the co-existence of renewable energy credits and GHG credit programs:

> The use of both RECs [renewable energy credits] and GHG credits should help ameliorate climate change. Nevertheless, there is a question of the most efficient way to achieve this objective: RECs alone, GHG credits alone, some combination of the two, or a different approach altogether. Were both programs administered jointly, the likelihood of making the right assessment would be much higher. . . . As it is today, however, there is no such assessment. State legislatures mandate REC use, but the federal government is the focus for climate change legislation.[248]

FERC, it should be noted, is wading tangentially into the waters of REC programs through Order No. 1000's requirement that transmission planning processes consider state public policy requirements (such as RECs), even as EPA proceeds with its proposals to regulate GHGs from stationary sources. The potential for EPA's initiatives to vie with the states' existing and ongoing initiatives in an inefficient way is obvious. Were FERC to take an environmentally inclusive approach, it could perhaps play a useful role in reducing the inefficiencies of this emerging dual federal-state regulatory regime.

Foregone synergies, which seem closely related to inefficiency, represent the loss of "potential *added* benefit of regulating a common subject in a coordinated way."[249] Here, Davies observes how EPA has considerable institutional knowledge dealing with emissions trading schemes from its SO_2 cap-and-trade program, whereas FERC (as discussed earlier) knows a great deal about wholesale electricity markets. Imagine that some kind of comprehensive federal emissions or clean energy trading scheme were put into place: "FERC staffers could draw on the experience of EPA employees who also were involved in

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[245] *Id.* at 500.
[246] *See id.*
[247] *Id.* at 501.
[248] *Id.* (citations omitted).
[249] *Id.*

SO_2 markets, and the EPA employees in turn might better administer the markets they oversee based on FERC's knowledge of electricity markets."[250]

Finally, incompleteness occurs when the fields fail to address critical questions that they might be more likely to take up if the fields were combined.[251] Davies describes in general terms the types of important challenges that an integrated approach to energy and environmental regulation might pursue, such as transitioning to renewable energy, achieving energy efficiency and conservation, changing the way energy is priced and used, and targeting our culture of dependence on fossil fuels.[252] More concretely, FERC might, for example, undertake with EPA and other agencies a comprehensive analysis of the electricity industry, identifying critical environmental challenges and opportunities for intervention.[253] The agencies might establish an efficient division of labor for tackling these challenges, with each agency focusing on its own area of expertise but also cooperating with other agencies to achieve regulatory synergies. FERC could undertake an analysis, for example, of how various rate structures in the industry encourage or discourage consumption of electricity versus conservation and investment in energy efficiency, and could seek to guide rate structures to reduce environmental costs and maximize overall welfare.[254] Many states are now experimenting with policies along these lines,[255] but there may be a valuable role for FERC to play in complementing these efforts.

Davies acknowledges the possibility that the division between environmental and energy regulation is actually a felicitous and "careful legislative balance of competing, yet equally valid, economic and environmental considerations."[256] But he concludes that "[g]iven how separately the two fields operate, however, that case is a hard one to make. Instead, it looks much more like inefficaciousness."[257] Davies' and our analysis and examples illustrate why this is the case: Quite simply, the benefits to the nation from environmentally inclusive FERC regulation seem far greater than the potential downside.[258]

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[250] *Id.* (citations omitted).
[251] *Id.*
[252] *Id.* at 504 (citations omitted).
[253] *Cf. generally* Freeman & Rossi, *supra* note 223 (discussing interagency decision-making and its benefits).
[254] Decoupling of utility revenues from sales of energy is an example of a rate-structure reform aimed at increasing utilities' incentives to invest in energy efficiency and conservation. *See generally Decoupling: Incentives for Energy Savings*, REGULATORY ASSISTANCE PROJECT, http://perma.cc/ZN5-4DKM.
[255] *See* FERC, RENEWABLE POWER & ENERGY EFFICIENCY: ENERGY EFFICIENCY RESOURCE STANDARDS (EERS) AND GOALS (2011), *available at* http://perma.cc/CS8P-TXMR.
[256] Davies, *supra* note 244, at 502.
[257] *Id.*
[258] These potential downsides include further costly regulation, superfluous regulation, conflicting regulation, turf battles between FERC and EPA, and difficulty at FERC rising to the challenge of complex environmental challenges.

ii. FERC's Position and Federal Regulatory Trends

FERC's position is increasingly out of step with federal regulatory trends toward considering the environmental costs and benefits of regulatory actions. First and foremost, FERC's position is in tension with NEPA, which states that "to the fullest extent possible . . . the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this chapter,"[259] namely, "to use all practicable means and measures . . . in a manner calculated to foster and promote the general welfare, to create and maintain conditions under which man and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations of Americans."[260] FERC has complied with many of NEPA's requirements and has admitted that CEQ regulations are binding on it—but only, FERC says, insofar as the regulations do not conflict with the Commission's statutory obligations.[261] Ultimately, the extent to which NEPA binds FERC is unsettled.[262] Regardless, as discussed above,[263] in complying with NEPA, FERC has categorically excluded its rate regulation from the need to perform environmental assessments or impact statements under NEPA, on the grounds that the Commission lacks authority to consider the environmental consequences of its rate regulation. We have already exposed the weaknesses of this justification. Although, as a practical matter, it may make sense for FERC not to engage in an environmental impact statement every time it reviews an individual rate filing, as doing so could hinder the agency's ability to perform its functions, FERC has invoked this categorical exclusion to justify its decisions not to perform environmental impact statements or assessments for rulemakings that fundamentally restructure aspects of the industry[264]—quite a different matter.

On a related note, CEQ has issued guidance instructing agencies to review their categorical exclusions periodically, as part of the agencies' obligation under CEQ regulations to "continue to review their policies and procedures and in consultation with [CEQ] to revise them as necessary to ensure full compliance with the purposes and provisions of [NEPA]."[265] The guidance explains why such review is important:

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[259] 42 U.S.C. § 4332 (2006).
[260] 42 U.S.C. § 4331 (2006).
[261] *See* Regulations Implementing National Environmental Policy Act of 1969, 52 FR 47897-01.
[262] While the Ninth Circuit has implied that CEQ's regulations bind all federal agencies, including independent agencies, *see* The Steamboaters v. FERC, 759 F.2d 1382, 1393 n.4 (9th Cir. 1985), the Supreme Court has not decided the issue, *see* Baltimore Gas & Elec. Co. v. Natural Res. Def. Council, Inc., 462 U.S. 87, 99 n.12 (1983) ("[W]e do not decide whether [CEQ's NEPA regulations] have binding effect on an independent agency."); *see generally* Pinney, *supra* note 15, at 390.
[263] *See supra* Part III.B.
[264] *See*, *e.g.*, Order No. 1000, *supra* note 94, at 49,963; Small Generator Interconnection Agreements & Procedures, 145 FERC ¶ 61,159, 2013 WL 6360657, at *65 (Nov. 22, 2013).
[265] Final Guidance for Federal Departments and Agencies on Establishing, Applying, and Revising Categorical Exclusions Under the National Environmental Policy Act, 75 Fed. Reg. 75,628, 75,636 (Dec. 6, 2010) (quotations omitted).

> CEQ believes it is extremely important to review the categorical exclusions already established by the Federal agencies. The fact that an agency's categorical exclusions were established years ago is all the more reason to review them to ensure that changes in technology, operations, agency missions, and the environment do not call into question the continued use of these categorical exclusions.[266]

With the need to address climate change more pressing than ever, with clean and renewable energy rapidly becoming a more important part of our electricity system, and with that system facing a critical juncture in terms of its future development, CEQ's exhortation seems especially applicable to FERC and its categorical exclusion for ratemaking. In general, NEPA and the trend of environmentally conscious regulation it has ushered in support the proposition that FERC should take a new course.

Other federal regulatory developments point in the same direction. Under Executive Order 12,866, federal executive agencies are required to assess the costs and benefits of proposed regulations and available regulatory alternatives, including inaction.[267] The purpose of the Social Cost of Carbon technical support documents released by the federal interagency working group is to "allow agencies to incorporate the social benefits of reducing carbon dioxide . . . emissions into cost-benefit analyses of regulatory actions that have small, or 'marginal,' impacts on cumulative global emissions."[268] Even before the release of that document, the Department of Transportation, Department of Energy, and EPA all incorporated GHG emission costs and benefits into cost-benefit analyses they performed pursuant to certain regulatory actions they undertook.[269] Although Executive Order 12,866 is not binding on independent agencies such as FERC,[270] it should have some persuasive significance for the Commission. The trend of regulatory consideration of environmental factors is reinforced by draft guidance issued by CEQ in 2010, proposing to advise agencies to "consider opportunities to reduce GHG emissions caused by proposed Federal actions and adapt their actions to climate change impacts throughout the NEPA process and to address these issues in their agency NEPA procedures."[271]

The trend may even be spreading to judicial review of FERC rate regulation. In recently upholding a series of FERC orders regarding rate design for proposed multi-state transmission projects in the Midcontinent Independent System Operator ("MISO") region that would facilitate the development of wind power, the Seventh Circuit stated that the project's promotion of wind power "deserves emphasis."[272] The court noted how wind power can reduce

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[266] *Id.* at 75,630.
[267] Executive Order 12,866, *supra* note 13, at § 1(a), (b)(6).
[268] 2010 Social Cost of Carbon, *supra* note 24, at 1.
[269] *Id.* at 2–3.
[270] Executive Order 12,866, *supra* note 13, at § 3(b).
[271] Memorandum from Nancy H. Sutley, Chair, Council on Envtl. Quality, to Heads of Fed. Dep'ts & Agencies, at 1 (Feb. 18, 2010), *available at* http://perma.cc/5DYF-KX27.
[272] Ill. Commerce Comm'n v. FERC, 721 F.3d 764, 774 (7th Cir. 2013), *cert. denied*, 134 S. Ct. 1277 (2014) and *cert. denied*, 134 S. Ct. 1278 (2014).

"both the nation's dependence on foreign oil and emissions of carbon dioxide," and emphasized the "substantial benefits" the region would likely reap as western wind power replaced "more expensive local wind power, and power plants that burn oil or coal."[273] FERC, in contrast, appears not to have invoked environmental benefits whatsoever in the orders.[274]

iii. FERC's Expertise

One of the arguments FERC has made justifying its exclusion of environmental considerations is that it lacks relevant expertise. For example, in rejecting invitations to mitigate potential increased NO_x emissions resulting from Order No. 888, FERC said it lacked the expertise to address technical aspects of the problem, such as determining a proper baseline for emissions and establishing whether emissions from a given plant contribute to damage in remote locations, concluding that EPA was better qualified to perform such tasks.[275] FERC had a point. EPA had and continues to have considerably more experience with and resources for such tasks, and with air pollution matters in general. FERC's concern is an important one that deserves serious consideration.

There are several counterarguments to FERC's concern, particularly as it relates to our specific proposal for FERC to address carbon emissions. First, FERC actually possesses unparalleled regulatory expertise in certain matters that are critical to important environmental aspects of the electricity industry. Two examples come readily to mind: wholesale electricity markets and transmission networks and planning. FERC was largely responsible for ushering in and designing wholesale electricity markets in the 1980s and 1990s. It exercises active oversight over them[276] and continues to tinker with their design.[277] These markets and their operators (largely the RTOs and ISOs, regulated by FERC) could play important roles in administering clean energy incentive schemes such as renewable portfolio standards involving renewable energy credits, or cap-and-trade allowances, because of their central role in coordinating and tracking electricity sales and flow.[278]

As for transmission, FERC has long had a significant role in its regulation and is assertively seeking to establish itself as the overseer of regional and

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[273] *Id.* at 775.
[274] *See* Midwest Indep. Transmission Sys. Operator, Inc., 133 FERC ¶ 61,221 (Dec. 16, 2010); Midwest Indep. Transmission Sys. Operator, Inc., 137 FERC ¶ 61,074 (Oct. 21, 2011).
[275] *See supra* Part III.B.
[276] Complaints that FERC's lax oversight of electricity markets was a contributing factor to the California energy crisis led the Commission to tighten its oversight. *See* McGrew, *supra* note 72, at 159.
[277] *See*, *e.g.*, Order No. 745, *supra* note 99; Order No. 741, Credit Reforms in Organized Wholesale Electric Markets, 133 FERC ¶ 61,060 (2010).
[278] *Cf.* Joseph T. Kelliher & Maria Farinella, *The Changing Landscape of Federal Energy Law*, 61 Admin. L. Rev. 611, 624 (2009) (noting that the proposed American Clean Energy and Security Act of 2009, H.R. 2454, 111th Cong. § 341 (2009)—the cap-and-trade bill known as the Waxman-Markey Bill—would have assigned the task of regulating carbon markets and trading to FERC).

interregional transmission planning processes and cost-allocation methods.[279] If Order No. 1000 is substantially upheld, FERC will be positioned to play an unprecedentedly central and centralizing role in coordinating and guiding the development of the nation's electricity grid. Effective development of the grid will be an essential part of the path to clean energy and smarter energy use, for a number of reasons. First, clean energy plants such as wind and solar will likely require construction of large new transmission facilities, because these energy sources are often most plentiful in locations far from load centers (areas, such as cities, where electricity is consumed in large amounts).[280] Second, the grid is due for hundreds of billions of dollars of investment over the next several decades, creating opportunities for progress.[281] Third, transmission can influence the generation mix in various and nuanced ways. Take, for example, the following statement from Midwest ISO's 2009 transmission expansion plan:

> Increased transmission capacity allows for greater access to less expensive generation. In many cases the generation with the lowest production cost has a higher CO_2 emission rate. In MTEP 08, the addition of the Appendix A/B projects relieved system constraints and allowed the system to dispatch lower cost steam turbine coal units in place of combined cycle and combustion turbines, thus increasing annual CO_2 emissions. While this increase represented a very small portion (0.23%) of the total CO_2 emissions, it demonstrates that transmission expansions can have the effect of increasing carbon production.[282]

Fourth, smart grid technology has the potential to be a crucial part of the transition toward clean energy and energy conservation and efficiency.[283] Finally, transmission planning and cost allocation have become contentious issues, with utilities disagreeing with one another, and states disagreeing with one another, about who should pay for what and what should be built.[284]

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[279] *See generally* Order No. 890, *supra* note 93; Order No. 1000, *supra* note 94.

[280] *See, e.g.*, Matthew L. Wald, *Wind Energy Bumps into Power Grid's Limits*, N.Y. TIMES, Aug. 27, 2008, http://perma.cc/CD5C-BUWJ.

[281] One industry study estimated that $298 billion of investment in transmission facilities would be needed between 2010 and 2030. THE EDISON FOUND., TRANSFORMING AMERICA'S POWER INDUSTRY 37 (2008). Other estimates have put the figure considerably higher. *See Hearing on Evaluating the Role of FERC in a Changing Energy Landscape Before the Subcomm. on Energy & Power of the H. Comm. on Energy & Commerce*, 113th Cong. 5 (2013) (statement of John R. Norris, Comm'r, Fed. Energy Reg. Comm'n), *available at* http://perma.cc/CE2Q-YSYS.

[282] MIDWEST ISO, MTEP 2009: MIDWEST ISO TRANSMISSION EXPANSION PLAN 37 (2009), *available at* http://perma.cc/B5A6-TJS8.

[283] *See Smart Grid*, OFFICE OF ELEC. DELIVERY & ENERGY RELIABILITY, U.S. DEP'T OF ENERGY, http://perma.cc/7V4M-CCFS. Congress has directed FERC to "adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability." Energy Independence and Security Act of 2007, Public Law No. 110-140, 121 Stat. 1492, § 1305(d) (to be codified at 42 U.S.C. § 17385(d)).

[284] *See* Order No. 1000, *supra* note 94, at 49,850 (citing a characterization by the Brattle Group); *see also* Ill. Commerce Comm'n v. FERC, 576 F.3d 470 (7th Cir. 2009) (litigation over these issues).

Thus, although FERC may lack expertise in some environmental issues, it has expertise in matters that are crucially related to important environmental aspects of the industry. Currently, FERC displays ambivalence in the way it regulates such matters and applies this expertise. It has taken a number of actions that have the effect of facilitating clean energy and conservation. Yet it consistently avoids performing environmental analyses or impact statements for its regulations, and has admitted that some of the goals it has pursued are in tension with environmental goals.[285] Rather than continue to engage in this awkward and likely inefficient dance of ambivalence and environmental regulation *sub silentio*, it may make more sense for FERC to acknowledge and embrace the role it has to play in shaping environmental policy relating to the industry.

Even if FERC currently lacks relevant expertise to handle some of the functions that would be entailed by considering environmental factors in its rate regulation, it would be theoretically possible to develop more expertise at FERC in these areas. Doing so might require FERC to shift staff and resources or obtain more resources.[286] The costs and benefits of shifting FERC's focus or investing this way in FERC would have to be weighed against the costs and benefits of alternative courses of action. To the extent that FERC's unique expertise in matters such as electricity markets and transmission is being underutilized from an environmental perspective, the investment may well be worth it. Alternatively, FERC could enlist the environmental expertise of other agencies, such as EPA, to complement its own core expertise.[287]

iv. Considerations Specific to Climate Change

As detailed in Part I, *supra*, existing regulation of the U.S. electricity industry does not adequately address GHG emissions from electricity consumption, and the cost of these emissions is estimated to be enormous. Cost internalization is a good way to do this; so are other measures paving the way for a grid that will facilitate clean energy.

Regulating carbon emissions, moreover, does not present the same technical and administrative difficulties that are involved in regulating traditional, criteria pollutants. In Order No. 888, one of FERC's arguments against proposals for it to adopt measures to mitigate any increased NO_x emissions from its regulation was the difficulty of designing and administering such a scheme.[288] Specifically, FERC said it lacked the expertise to determine a proper emissions baseline and to establish whether emissions from a given plant contribute to

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[285] *See* Order No. 888, *supra* note 82, at 21,673.

[286] FERC is funded through fees charged to the industries it regulates. *About FERC*, FERC, http://perma.cc/QV8E-ETVC.

[287] *See* Freeman & Rossi, *supra* note 223, at 1157 (noting that "[a]s a general matter, absent a statutory prohibition on agencies' consulting each other, there appears to be no legal bar to such interactions"); *see generally* Jason Marisam, *Interagency Administration*, 45 Ariz. St. L.J. 183, 190–91 (discussing practice of agencies seeking expertise of other agencies).

[288] Order No. 888, *supra* note 82, at 21,672–73.

damage in remote locations.[289] In contrast to NO_x and other traditional pollutants, greenhouse gas emissions are dispersed globally in the atmosphere. While it is true that different geographic areas are suffering and will continue to suffer different types and levels of harms from global warming, the risks and costs are uniform enough that regulators here and abroad have found it adequate to adopt unitary prices for the global social costs of carbon emissions (though these prices increase as atmospheric carbon levels increase). This defining characteristic of these emissions makes it much easier for FERC to design and administer schemes to address these emissions. Drawing on existing climate change science and regulatory approaches to the problem, FERC could likely competently manage such a task.

v. A History of Radical Reforms, with Court Approval

Finally, it is relevant that courts have approved radical changes in policy and FPA interpretation by FERC in the past, demonstrating the particularly broad deference granted to FERC. In *California ex rel. Lockyer v. FERC*,[290] the Ninth Circuit upheld FERC's decision to allow wholesale sales of electricity at market-based rates. The court noted that "the Supreme Court has emphasized 'that the just and reasonable standard does not compel the Commission to use any single pricing formula'" and that "the 'just and reasonable' requirement accords FERC 'broad rate-making authority.'"[291]

In *New York v. FERC*,[292] the Supreme Court upheld Order No. 888's imposition of an open access requirement on unbundled retail transmissions in interstate commerce.[293] The Court reached its holding based on FERC's authority under section 201(b) of the FPA to regulate "the transmission of electric energy in interstate commerce," which is not limited to wholesale transactions, unlike its jurisdiction to regulate "the sale of electric energy at wholesale in interstate commerce."[294] The Court accepted FERC's reasoning that an unbundled retail transaction could be broken down into two products—transmission service and the sale of the power itself—and that FERC could regulate the transmission element. The state of New York had argued that FERC was intruding on an area of state regulation protected by the prefatory language of section 201(a), which limits FERC's authority "to those matters which are not subject to regulation by the States."[295] But the Court said its FPA jurisprudence made clear that "the FPA authorized regulation of wholesale sales that had been previously subject to state regulation,"[296] and that section 201(a)'s language reserving powers to

[289] *Id.* at 21,672.
[290] 383 F.3d 1006 (9th Cir. 2004).
[291] *Id.* at 1012 (citing Mobil Oil Exploration & Producing Se. Inc. v. United Distrib. Co., 498 U.S. 211, 244 (1991)).
[292] 535 U.S. 1 (2002).
[293] *Id.* at 16–24.
[294] *Id.* at 18–19.
[295] *Id.* at 20–21.
[296] *Id.* at 21 (citing Public Util. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83, 85–86 (1927)).

the states is a "mere policy declaration that cannot nullify a clear and specific grant of jurisdiction. . . ."[297] The Court also reasoned that unbundled transmissions were a new development and thus were not regulated by the states when the FPA was passed, making this provision of section 201(a) irrelevant.[298] This last conclusion is significant, because the Court effectively approved an expansion of FERC's exercised jurisdiction into retail transmissions, an area traditionally regulated by the states. In doing so, the Court noted the major changes that had occurred in the electricity industry, including unbundling, since the FPA's enactment.[299]

Jody Freeman and David Spence cite FERC's market-based rate and open-access reforms in concluding that "FERC led the way toward more competitive markets by using the regulatory levers it had, arguably going beyond what Congress had anticipated."[300] For FERC to begin incorporating environmental considerations into its rate regulation would arguably just be a new chapter in this history of innovation.

C. NEPA Kicks In

Once FERC acknowledged its *authority* to incorporate environmental considerations into its rate regulation, NEPA would then trigger a *duty* to consider the environmental consequences of some of these actions. NEPA requires that federal agencies proposing major federal actions significantly affecting the quality of the human environment perform an EIS and identify alternatives to the proposed actions, among other things.[301] As described *supra*,[302] FERC has categorically excluded its rate regulation actions from the need for EISs or EAs, arguing that these actions are not major federal actions within the meaning of NEPA because they are not actions with environmental effects that are "actually or potentially subject to federal control or responsibility." FERC's reasoning is that the FPA precludes it from having control or responsibility over these environmental effects. Interpreting the FPA to give FERC authority to incorporate environmental considerations into its rate regulation would nullify this argument by giving FERC control and responsibility over these effects. FERC would have to withdraw or substantially revise its categorical exclusion to reflect the fact that rate regulation actions that would have a significant impact on the environment would require EISs. FERC would be subject to at least a minimum procedural obligation to consider environmental costs and benefits in these. Yet FERC could still go beyond this: Its authority to incorporate environmental considerations into the determination of just and reasonable rates would give it broad substantive power to adjust rates, regulations, practices, and the like in order to address environmental problems.

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[297] *Id.* at 22 (internal quotations omitted).
[298] *Id.* at 21.
[299] *Id.* at 23.
[300] Freeman & Spence, *supra* note 21.
[301] 42 U.S.C. § 4332(2)(C) (2006 & Supp. V 2012).
[302] *See supra* Part III.B.

V. Implementation Illustrations

This Part presents several illustrations of the types of policy reforms FERC could undertake or have undertaken under an environmentally inclusive approach to rate regulation. The first illustration takes a prior reform promulgated by FERC, Order No. 745, and imagines how it could have been improved through the process of an EA and/or EIS and through substantive incorporation of environmental costs and benefits. The second and third illustrations imagine wide-reaching reforms that might be possible in the future. For each illustration, we explore what the reform might achieve as well as what problems or challenges it might entail. In doing so, we hope to give a general sense of the types of reforms that might be possible and what types of goals would be attainable under an environmentally inclusive approach, while also highlighting the challenges and limitations that would be presented by factors such as FERC's limited jurisdiction under the FPA and the realities of the Commission's institutional competence. In keeping with the focus of this Article, the reform proposals focus mostly on reducing carbon emissions, but it is possible to imagine the reforms extending to incorporate other pollutants and environmental problems, and at times we explicitly discuss this possibility.

A. Environmental Impacts of Order No. 745

In Order No. 745, FERC invoked its section 206 authority to direct that providers of demand response in real-time and day-ahead wholesale energy markets be compensated at the full market price for energy (called "LMP," for "locational marginal price") when certain conditions are met that ensure that the use of demand response will be cost-effective.[303] Commenters on the proposed order were divided as to whether demand response providers should be paid this full market price or, alternatively, the full market price minus the generation (denoted as "G") component of the retail rate.[304] Supporters of full LMP argued, among other things, that functional equivalence between demand response and generation, as well as imperfections in energy markets, made full LMP appropriate.[305] The primary rationale behind the LMP-G approach was that payment of full LMP would overcompensate demand response providers by failing to take into account the retail rate savings that the demand response provider reaps from foregoing energy consumption.[306] Taking a full social cost view, some commenters argued that even full LMP would undercompensate the demand response provider, given the environmental benefits of reduced energy consumption.[307]

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[303] Order No. 745, *supra* note 99, at 16,658.
[304] *Id.* at 16,662–64.
[305] *Id.*
[306] *Id.* at 16,662–63.
[307] *Id.* at 16,664.

In May 2014, the D.C. Circuit vacated Order No. 745 in a 2-1 ruling, finding it an impermissible regulation of retail rates.[308] The majority further stated that it would also have struck down the order as arbitrary and capricious, faulting FERC for inadequately responding to arguments that the order would overcompensate demand response.[309] In reaching its decision, the majority took a restrictive view of FERC's authority under the FPA and chose to emphasize the retail-market aspects of demand response, despite the effects the majority conceded demand response has on wholesale rates.[310] Although the court's ruling rendered Order No. 745 inoperative, it is still instructive to consider how the order could have been improved through environmentally inclusive decision-making.

In deciding to adopt the full LMP approach, FERC did not remark on the environmental aspects of the problem, other than to mention the comments regarding the potential environmental benefits. Moreover, pursuant to its categorical exclusion of ratemaking actions from NEPA, it declined to perform an EA or EIS for Order No. 745.[311] The record, therefore, suggests that environmental considerations barely, if at all, informed the Commission's decisionmaking. Order No. 745 is a good example of a FERC action that would have benefited from consideration of environmental factors. This is largely because demand response is a phenomenon of considerable environmental consequence that nevertheless seems largely to fall through the gaps of environmental regulation.[312]

Under a policy of environmentally inclusive rate regulation, in which significant reforms of the industry would not be categorically excluded from NEPA, FERC would have had to undertake an EA to determine if its proposed rule might have a significant impact on the environment. At the EA stage, and at the EIS stage if an EIS were undertaken, FERC would have been obligated to examine reasonable alternatives to its proposed rule—including alternatives beyond its jurisdiction—and the environmental consequences of these alternatives.[313] It could, for example, have assessed what impacts various alternatives (LMP, LMP-G, no action) would have had on aggregate demand response output across the country, and what impacts demand response had on the environment (here, FERC might well have considered the benefits not just of GHG emissions avoided but of all pollution avoided under various demand response scenarios involving different generation mixes). While these may have been

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[308] Elec. Pwr. Supply Ass'n v. FERC, No. 11-1486, slip op. at 14, 16 (D.C. Cir. May 23, 2014).
[309] *Id.* at 14–16.
[310] *See id.* at 7–11. The dissent argued that a sufficient connection existed between the forms of demand response regulated by Order No. 745 and wholesale rates to support the order, and that FERC adequately explained its decision to use full LMP. *Id.* at 13–27 (Edwards, J., dissenting).
[311] *Id.* at 16,677.
[312] Congress does not appear to have specifically delegated to any entity plenary environmental authority over demand response. Although the EPA is exercising regulatory oversight over behind-the-meter backup generators used by some demand response providers, this is different altogether from rewarding demand response for any environmental benefits it produces. *See* New Source Performance Standards for Stationary Internal Combustion Engines, 78 Fed. Reg. 6674 (2013) (to be codified at 40 C.F.R. pts. 60, 63).
[313] *See* 40 C.F.R. §§ 1502.14–16.

challenging investigations to undertake,[314] they could have produced extremely valuable information about demand response and its role in the nation's electricity system and have promoted sound policymaking by the Commission with a view to total social costs and benefits.

Through an EA or EIS, FERC could, for example, have explored in more depth and evaluated the types of environmental arguments made by the commenters on Order No. 745. These arguments include claims that demand response is environmentally valuable because it tends to replace the particularly dirty generation sources that are used to meet peak electricity demand, as well as counterarguments that paying demand response providers full LMP will encourage them to provide demand response services while actually running dirtier, off-grid power simultaneously.[315] In a world without an environmental-energy regulatory divide, answering questions like these would be critical to forming sound policy on the issue of demand response. An EA or EIS would have allowed FERC to collect and analyze data to try to confirm or disconfirm such claims, and would have allowed the Commission to consider regulatory alternatives to mitigate environmental harms. For example, if FERC had determined that paying full LMP would indeed be likely to cause some demand response providers to operate off-grid power that is dirtier than the generation replaced by the demand response, FERC could have considered including in Order No. 745 a requirement that demand response providers certify, under threat of penalty, that they will not engage in such practices.[316] In short, performing an EA or EIS would have allowed FERC to make an environmentally informed decision that would maximize total welfare, rather than ignoring the environmental aspects of the problem.[317]

We can also imagine what the details of the substantive rules laid out in Order No. 745 might look like if they had incorporated environmental costs and benefits. In the process, we can gain some insight into how incorporation of environmental costs and benefits into FERC regulation would fit into rate regulation doctrine developed by FERC and the courts under the FPA.

Let us imagine that FERC performed an EIS and arrived at a rough monetary estimate of the benefits that demand response, on average, provided in terms of avoided environmental externalities.[318] Let us assume further that, fac-

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[314] To assist with the investigation, FERC could solicit data and analysis by interested parties, including major demand response service providers, environmental groups, and electric utilities.

[315] Order No. 745, *supra* note 99, at 16,664.

[316] Such a requirement could be justified under an environmentally inclusive reading of the FPA because it would help ensure that wholesale electricity rates are not unjust or unreasonable by virtue of producing excessive environmental externalities.

[317] Citing any environmental benefits likely to redound from the order could also have helped FERC to justify legally its decision to require full LMP compensation for demand response providers, as this compensation could have been viewed as partly for these benefits. More generally, to the extent FERC continues to undertake industry reforms likely to produce environmental benefits, explicit recognition of these benefits by FERC could help shore up these reform efforts against legal challenges that the reforms are arbitrary and capricious.

[318] It is possible to imagine FERC taking a more case-specific approach to valuing the environmental benefits of demand response and requiring that demand response providers be compensated at a level that would account for the avoided environmental externalities of the particular

toring this value into the equation, FERC arrived at some formula (say, LMP plus some constant *k*) as the appropriate compensation level(s) for demand response. FERC would still need to address the issue of cost allocation—who should pay demand response providers for their services, and in what proportion—including as it relates to the environmental costs and benefits at issue.[319] FERC cost allocation issues are governed by certain judicially endorsed principles, particularly those of "cost causation" (the principle that customers should pay for the costs they cause to be incurred) and "beneficiary pays" (the principle that, to justify socialized cost allocation to ratepayers for facilities, FERC must outline the system-wide benefits the new facility provides with "reasonable particularity").[320] In Order No. 745, FERC adopted a rule that costs be allocated "proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response resource reduces the market price for energy at the time when the demand response resource is committed or dispatched," finding that this would "reasonably allocate the costs of demand response to those who benefit from the lower prices produced by dispatching demand response."[321]

Incorporating environmental costs and benefits into ratemaking would introduce new dynamics into the application of these cost-allocation principles, which did not evolve to address environmental considerations. The cost-causation principle in particular is centered around private, not social, cost: It concerns what costs a customer of a utility (or utilities) has caused *the utility (or utilities), not society*, to incur. But it is possible to imagine adapting the principle quite seamlessly to encompass social costs: The revised version would dictate that customers pay for the full social costs they cause to be incurred. The beneficiary-pays principle, insofar as it applies,[322] is trickier to adapt. That is because environmental harms are often significantly removed in time and space from their cause, and in a widely, unevenly dispersed manner. Benefits of reduced carbon emissions from a power plant in Iowa, for example, are realized around the world, such as by residents of the Maldive Islands. Clearly, FERC lacks jurisdiction to require people in the Maldive Islands to pay for such benefits, and even in cases where FERC possesses sufficient jurisdiction, determining who exactly reaps environmental benefits and in what amount, and then distributing those costs appropriately, could be a highly complex undertaking, with the complexity varying according to the pollutant or environmental prob-

generation output that the demand response replaced. This would require the operator of the wholesale market to determine which generation source was being replaced and what type of pollution profile it had—a process that operators of wholesale electricity markets could carry out through databases and algorithms.

[319] *See* Order No. 745, *supra* note 99, at 16,673–74.

[320] Gabe Maser, *It's Electric, but FERC's Cost-Causation Boogie-Woogie Fails to Justify Socialized Costs for Renewable Transmission*, 100 GEO. L.J. 1829, 1834–35 (2012); *see also* Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 476 (7th Cir. 2009).

[321] Order No. 745, *supra* note 99, at 16,674.

[322] Some confusion appears to exist concerning the exact meaning of and relationship between the cost-causation and beneficiary-pays principles, such as around the issue of when FERC can rely on the beneficiary-pays principle. *See* Midwest Indep. Transmission Sys. Operator, Inc., 137 FERC ¶ 61,074, 2011 WL 5116434, at *11 (Oct. 21, 2011) (comments of Illinois Commission).

lem at issue. However, costs imposed under the beneficiary-pays principle need only be "at least roughly commensurate" with anticipated benefits.[323]

Applying these principles to the demand response context, the question is whether FERC could find a legally acceptable way to allocate the portion of a demand response payment that is attributable to avoided environmental costs, and what this way would look like. Attempting to adhere strictly to the cost-causation or beneficiary-pays principles would result in different results depending on which principle was invoked. Under the cost-causation principle, the portion of the payment might be allocated according to the same system that FERC adopted in Order No. 745: "proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response resource reduces the market price for energy at the time when the demand response resource is committed or dispatched."[324] Under the beneficiary-pays principle, the portion of the payment should ideally be distributed among those who benefit from the avoided environmental costs, but this represents an ideal that is all but impossible to achieve.

FERC might thus want to stick with the cost allocation method under the cost-causation principle and argue that the costs imposed would be roughly commensurate with the environmental benefits received. FERC might be aided here by the fact that the Seventh Circuit recently upheld a set of cost allocation determinations by FERC with respect to proposed multi-state transmission projects in the MISO region despite the fact that it was "impossible to allocate [certain identified] cost savings . . . with any precision across MISO members."[325] Moreover, pointing to how wind power can reduce "both the nation's dependence on foreign oil and emissions of carbon dioxide," the court noted approvingly how the projects would promote wind power.[326] Writing for the court, Judge Richard Posner cited the "substantial benefits" the region would likely reap as western wind power replaced "more expensive local wind power, and power plants that burn oil or coal . . . ."[327] The court stated that there was "no reason to think these benefits will be denied to particular subregions of MISO."[328] In other words, the court approvingly cited the environmental benefits likely to result from the project despite the difficulty of allocating these benefits.

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[323] *Ill. Commerce Comm'n*, 576 F.3d at 477 (holding that FERC need not calculate anticipated reliability benefits of a transmission project to the "last . . . ten million or perhaps hundred million dollars").
[324] Order No. 745, *supra* note 99, at 16,674.
[325] Illinois Commerce Comm'n v. Fed. Energy Regulatory Comm'n, 721 F.3d 764, 774 (7th Cir. 2013), *cert. denied*, 134 S. Ct. 1277 (2014) and *cert. denied*, 134 S. Ct. 1278 (2014).
[326] *Id.* at 774–75.
[327] *Id.* at 775.
[328] *Id.*

B. Transmission Planning

A reform that FERC could implement in the future would be to require or encourage consideration of carbon emissions in regional and interregional transmission planning.

i. How It Would Work

In undertaking this reform, FERC could assert a special need to take action to reduce carbon emissions from electricity generation, in light of the failure of existing regulation to address the problem. FERC would acknowledge the importance of transmission planning to this goal,[329] and the shortcomings of existing planning in making adequate progress toward this goal. Implicit in this point is the fact that FERC has primary authority over and unparalleled expertise with transmission planning, making it appropriate for FERC to take action.

Then would come the concrete substance of the regulation: FERC could adopt the federal interagency group's mean estimate of the social cost of carbon[330] and state that all regional and interregional transmission planning should from now on reflect, such as in its cost-benefit calculations, this cost.

FERC would be faced with some choices in implementing this regulation in detail. FERC could choose between making the requirement of considering carbon emission costs and benefits a merely procedural one or a substantive one. A procedural requirement would simply provide that the parties involved in transmission planning would identify and assess the emission costs and benefits. A substantive requirement would direct these parties to literally factor these emission costs and benefits into the cost-benefit calculations that determine which transmission projects get built. Clearly, a substantive requirement of this type has much more force, and it would almost certainly lead to vigorous challenges arguing that this is beyond FERC's authority. Alternatively, FERC could take a voluntary approach and simply encourage, rather than require, that transmission planning incorporate the social cost of carbon emissions. FERC has issued optional regulations in the past, including Order No. 2000, which encouraged but did not require the formation of RTOs.[331] Another

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[329] It is quite possible that even if comprehensive federal cap-and-trade or carbon tax legislation were passed, the complexities of transmission planning, with its collective action problems and monopolistic aspects, would still stand in the way of optimal GHG reductions and clean energy deployment. *Cf.* Kelliher & Farinella, *supra* note 278, at 623 (arguing that achieving maximum wind power potential is unlikely under the current state siting regime, and that exclusive and preemptive federal siting of transmission facilities would be necessary). Kelliher was Chairman of FERC from 2005 to 2009. *Id.* at 611.

[330] We focus on the social cost of carbon throughout this Part because the federal government has produced an estimate for the cost of carbon, but not other types of GHG emissions yet. But FERC could, at an appropriate time, expand its programs to encompass the social costs of other GHG emissions.

[331] Order No. 2000, *supra* note 90, at 4.

alternative—a middle ground between voluntary and mandatory regulation—would be for FERC to provide incentives to utilities to comply.[332]

Also, FERC would need to decide whether jurisdictional entities should use the domestic or global cost of carbon in their calculations. The argument for global cost is that it reflects the full cost to society, and that it is appropriate for FERC-jurisdictional entities to account for the full social costs of their actions.[333] The argument for domestic cost is that it reflects the cost to the United States, that FERC has jurisdiction only within the United States, and that counting benefits (i.e., of avoided carbon emissions) to people outside the United States while imposing all the costs (i.e., of higher electricity prices) associated with those benefits on U.S. individuals and entities violates the beneficiary-pays principle. If FERC wanted to require transmission planning to reflect and incorporate the global cost of carbon, the agency might need to argue that the principle simply should not apply to its efforts to internalize these costs, but a court reviewing the decision might disagree. Alternatively, FERC could adopt the domestic cost approach and argue that, in an aggregate sense, applied to transmission planning across the country, this approach would lead to a roughly commensurate distribution of costs and benefits incurred by customers, with the vast majority of U.S. customers paying to avoid carbon emissions that would harm the whole country, themselves included. Customers in each region would pay to avoid emission costs imposed on the entire country, but customers in other regions would reciprocate, balancing out the distribution of costs and benefits. Another choice FERC would have to make is whether to require the transmission planning processes to use lifecycle carbon emission analysis, or to require consideration of emissions produced by the generation process only. Lifecycle analysis provides a comprehensive accounting of all the emissions associated with an energy source, from harvesting of the fuel source to management of waste generated by the production process.[334] This approach would be more challenging and expensive for FERC to administer and for regulated entities to comply with, but would provide a more accurate evaluation of total emissions costs and benefits associated with proposed transmission projects. Whether FERC used lifecycle analysis or not, it might want to assign generic social cost intensity figures for various types of generation—coal, wind, etc.—corresponding to their carbon intensity and require use of these

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[332] FERC took a partly incentive-based approach in Order No. 888 by adopting a policy that non-public utility transmission providers, over which FERC lacked jurisdiction, would be granted open access service only if they agreed to provide open access to their own transmission facilities. Order No. 888, *supra* note 82, at 21,572–73. FERC also used incentives to encourage utilities to join RTOs, such as by conditioning merger approval on joining. Joel B. Eisen, *Regulatory Linearity, Commerce Clause Brinksmanship, and Retrenchment in Electric Utility Deregulation*, 40 WAKE FOREST L. REV. 545, 573–82 (2005).

[333] *Cf.* 2010 SOCIAL COST OF CARBON, *supra* note 24, at 10–11 (weighing advantages versus disadvantages of using the domestic versus global figures, and concluding that "a global measure" of benefits from avoided emissions was "preferable," despite OMB guidance requiring analysis of economically significant regulations from a domestic perspective and merely allowing analysis from international perspective).

[334] *See supra* note 35 for an explanation of lifecycle analysis.

figures in the cost-benefit calculations unless an entity could show that the anticipated emissions associated with a particular project would differ significantly from the standard value for that type of project.[335]

ii. Challenges

Is FERC qualified to undertake the task of reviewing carbon emission costs and benefits of various transmission plans? Are utilities and RTOs and ISOs qualified to implement such a program? Given FERC's expertise in transmission matters, the answer to the first question is probably yes. And Midwest ISO's thorough incorporation of costs and benefits related to anticipated GHG emission regulation costs into its planning[336] suggests that RTOs and ISOs—and the utilities that form them—are capable of implementing the program.

Another concern regarding the proposal is that it would increase the difficulty and expense of transmission planning. Although performing the type of analysis that Midwest ISO performed would entail costs, the process would help ensure that transmission projects get selected and built in a way that would minimize the social cost of generation, potentially saving billions of dollars in climate damage to the United States alone. Moreover, mandating that transmission planning incorporate the costs and benefits of carbon emissions might actually eliminate some of the conflicts over transmission planning and cost allocation that are currently being caused by conflicting state public policy requirements, by establishing a floor level of credit to be given to transmission facilitating clean energy in cost-benefit calculations.

A limitation of this approach is that it would only indirectly influence emissions from future generation facilities, by incentivizing the development of transmission that would facilitate clean energy. But since intelligent transmission development is essential to the optimal development of clean energy, this would be no small achievement.

C. Social-Cost Wholesale Rates

i. How It Would Work

A more ambitious and radical approach would be for FERC to require—or encourage, perhaps through incentives—that the social cost of carbon be internalized into wholesale electricity rates. Again, through a rulemaking, FERC would first announce a new interpretation of the FPA and an accompanying general policy of incorporating environmental considerations into the determination of just and reasonable rates where appropriate. FERC could then issue

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[335] California's Low Carbon Fuel Standard takes this type of approach. *Id.*

[336] *See generally* MIDWEST ISO, 2010 TRANSMISSION EXPANSION PLAN 140–59 (2010), *available at* http://perma.cc/A9G5-7PBV (quantifying financial values of transmission plans under various regulatory scenarios, assigning dollar values to reductions in carbon emissions).

new regulations to ensure that externalities from carbon emissions are internalized in both market- and cost-of-service-based wholesale electricity sales.

a. Market-Based Context

Wholesale electricity markets give FERC a rather elegant way to ensure that these externalities are internalized: a system of generation dispatch called social-cost dispatch.[337] Under this system, the operators of an electricity market dispatch generation on the basis of its full social cost rather than its private cost. Thus, a wind farm might be dispatched over a coal plant to meet demand at some moment in time because of the former's lack of emissions, whereas if those emissions were not factored into the equation, the coal plant might be dispatched over the wind farm. FERC could mandate that wholesale market sales of electricity reflect and incorporate the cost of carbon, and allow wholesale market operators (such as RTOs and ISOs) to meet this requirement through social cost dispatch. The price at which sales would take place would still be the private price, but social cost would be used to determine[338] which generation bids are selected.

The effect would resemble that of a carbon tax, internalizing the social cost of carbon into the price of electricity bought and sold through wholesale electricity markets. However, there would be no actual tax revenue to be collected since the sale price would remain private cost. Thus, there would be no need for FERC to collect any tax, avoiding a considerable administrative, legal, and political complication. To avoid overpenalizing emissions already being penalized under other regulations, such as a state cap-and-trade program, FERC could implement a mechanism whereby market operators, perhaps upon application by a generator or an electricity wholesaler, could prorate the FERC-pursuant internalization amount for particular generators or wholesalers so as to ensure that no more than the total social cost of carbon is internalized.

b. Cost-of-Service-Based Context

Many wholesale electricity sales do not take place through markets but still take place under cost-based FERC regulation. Electricity wholesalers file rates, terms, and conditions with FERC in accordance with the FPA,[339] and FERC reviews these to ensure they meet the FPA's standards.[340] FERC could require that the social cost of carbon associated with these sales be internalized into these rates. Yet such a system would likely require FERC to collect this "internalization surcharge" (again, similar to a carbon tax) as a tax so as not to result in the utilities' being paid for the surcharge, opening up a host of compli-

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[337] Social cost dispatch has been around in theory and in practice for several decades now. *See, e.g.*, Stephen Bernow et al., *Full-Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation*, 4(2) THE ELECTRICITY J. 20 (1991).
[338] Social cost would become the relevant cost consideration involved in dispatch. Other considerations, such as system reliability, also factor into dispatch and would continue to do so.
[339] *See* 16 U.S.C. § 824d(d) (2012).
[340] 16 U.S.C. § 824d(e) (2012).

cations, such as whether FERC has authority to levy and collect such a tax[341] and whether it would be politically possible for it to do so.[342] This complication shows how FERC's limited statutory authority constrains the agency's ability to tackle environmental problems in a comprehensive way—a truth this Article readily admits.

ii. Challenges

Any FERC effort to internalize the social cost of carbon into wholesale electricity rates would be constrained in significant ways by FERC's limited jurisdiction. For example, the effort could create perverse incentives. First, FERC's lack of jurisdiction over retail sales of electricity might lead sophisticated customers currently purchasing from middlemen to buy directly from electricity generators, or generate their own electricity from dirtier generators, avoiding FERC's wholesale regulation and the internalized carbon cost. Second, FERC's lack of jurisdiction over state-owned utilities and rural electric cooperatives[343] might incentivize energy-intensive businesses to move where these utilities (confusingly called "non-public utilities" in FERC parlance) operate, if internalizing the cost of carbon would lead their rates to be higher than the rates they could get from these non-public utilities. Jurisdiction-evading responses like these would undermine the effectiveness of FERC's effort to reduce carbon emissions, and could lead to considerable inefficiency.

Moreover, the program would pose a risk of conflict with other regulations that address carbon costs. Theoretically, as mentioned above, FERC could allow complying entities to show exactly what their carbon emission rates are, and to what extent carbon costs are already being internalized in the wholesale sales they conduct, and then to comply with FERC's program by ensuring that

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[341] Under the current FPA, FERC would have to argue that the statute gives it implied authority to levy and collect such a tax to ensure just and reasonable rates. Courts would likely be highly skeptical toward this position, given its novelty. Applying *Chevron*, a court might hold that the FPA clearly does not give FERC authority to administer such a tax, or might conclude that the statute is ambiguous on this question, but that FERC's interpretation is unreasonable. Even if a court upheld FERC's claim of authority, the delegation of authority would still have to pass nondelegation scrutiny. A delegation of power by Congress must provide the agency with an "intelligible principle" to which the agency must conform. Whitman v. Am. Trucking Assoc., 531 U.S. 457, 472 (2001). The delegation of discretionary authority under Congress' taxing power is subject to no constitutional scrutiny greater than that applied in other nondelegation contexts. Skinner v. Mid-Am. Pipeline Co., 490 U.S. 212, 214 (1989). Modern nondelegation doctrine is rather toothless, but a court might still conclude that the FPA's "just and reasonable" language provides too little content to serve as an intelligible principle for the administration of a tax.

[342] Because FERC would at the very least need to ensure that these tax revenues were serving the end of just and reasonable rates, it could establish programs for the reinvestment of the tax revenues in beneficial energy programs, such as subsidies to help low-income customers afford the higher rates that would result, cost-effective energy efficiency initiatives, and smart grid research. Notably, many of the largest American corporations, "including Exxon Mobil, Walmart, and American Electric Power, are incorporating a price on carbon into their long-term financial plans." Coral Davenport, *Large Companies Prepared to Pay Price on Carbon*, N.Y. TIMES, Dec. 5, 2013, at A1.

[343] *See* 16 U.S.C. § 824(f) (2012).

total cost internalization for these sales equals FERC's adopted social cost of carbon figure. In practice, however, such a measure could be complicated and difficult to implement accurately. Moreover, FERC's program might force states to reevaluate their ongoing and planned policies to address the cost of carbon or incentivize clean energy. FERC's program would also stand somewhat awkwardly alongside EPA efforts such as the PSD and Title V programs as they applied to GHG emissions, but would not conflict per se with these efforts.

Other drawbacks include the reality that FERC's effort would be sure to meet major industry and political resistance, perhaps even sparking backlash in Congress and an effort to amend the FPA and curtail FERC's authority. The backlash would largely focus on one effect that FERC's effort would have: raising electricity bills, which could produce an economic slowdown and hurt low-income consumers in particular. Two measures FERC could take to minimize such effects would be to phase internalization in gradually (as tends to occur in cap-and-trade systems[344]) to avoid an economic shock, and establishing programs to help low-income consumers afford the higher rates. Yet the latter measure, like administration of a tax, may be outside FERC's authority.

Finally, there are the questions of whether FERC is qualified to undertake such a program, and whether complying entities that would have important responsibilities in implementing it, especially wholesale market operators, are qualified to do so. The sophistication of FERC and these entities in the economic and technical aspects of wholesale electricity transactions suggests that they would be able to implement this program, which relies on simple cost internalization, effectively. The considerable literature on and substantial experimentation that has occurred with environmental and social cost dispatch suggests that wholesale market operators in particular would be well equipped to implement the program. Further, FERC could seek EPA's expertise in developing the environmental aspects of the program, such as the carbon intensities of various types of generation. Thus, this does not seem as large of a concern as FERC's jurisdictional limitations.

D. Comprehensive Incorporation of Environmental Considerations

Finally, it is worth thinking about what it might look like if FERC took a comprehensive approach to incorporating environmental factors into its rate regulation—if "economic" and "environmental" regulation of the electricity were, as Lincoln Davies imagines,[345] merged. FERC might cooperate with EPA and other agencies to undertake a comprehensive and holistic analysis of the electricity industry, identifying critical environmental challenges and opportunities for intervention.[346] The agencies might establish an efficient division of

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[344] *See supra* Part I.B.ii.
[345] *See supra* Part IV.B.i.
[346] *Cf. generally* Freeman & Rossi, *supra* note 223 (discussing interagency decision-making and its benefits).

labor for tackling these challenges, with each agency focusing on its own area of expertise but also cooperating with other agencies to achieve the regulatory synergies that Davies discusses. Were EPA to take the lead in promulgating a comprehensive program to reduce GHG emissions, it could draw on FERC's expertise in electricity markets in designing the program, and perhaps involve FERC in aspects of the program's administration. FERC could undertake an analysis of how rate structures still prevalent in the industry generally encourage consumption of electricity rather than conservation and investment in energy efficiency, and could seek to complement state efforts to find rate designs that reduce environmental costs and maximize overall welfare.[347] There would likely be many other opportunities for FERC to take an active role in promoting a sustainable and cleaner electricity system. We offer these suggestions merely to provide a glimpse of what might be possible.

Conclusion

The time has come to rethink FERC's policy of excluding environmental considerations from its wide-ranging regulation of the electricity industry under sections 205 and 206 of the FPA (what we have referred to as FERC's "rate regulation" for convenience's sake). FERC's rationales for its current policy are unconvincing. Its narrow view of its authority to consider environmental consequences is arguably too restrictive. Its policy is also increasingly at odds with its own embrace and pursuit, however tacit, of environmental goals. Finally and most fundamentally, it is difficult to justify FERC's neglect of environmental considerations as good policy today. Although it may once have seemed defensible to divide energy or economic regulation (i.e., by FERC) from environmental regulation (i.e., by EPA) of the electricity industry and pit them against each other to some degree, such an approach seems deeply wrong in an era in which we increasingly view sustainability and economic growth as interrelated and inseparable, and when we face an environmental threat of unprecedented proportions in climate change. In the absence of adequate congressional action to correct this problem, FERC would do well to explore the possibility that its "just and reasonable" mandate must evolve to encompass these defining issues of our time.

[347] *See supra* notes 254 and 255 and accompanying text.