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U.S. climate policy and the regional economics of electricity generation

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ABSTRACT

We examine the interaction between price competition and policy in four ISO markets by modeling the economic dispatch of generation technologies and the evolution of generation resources over a fifteen year period beginning in 2016. Using a representative range of forward prices for natural gas and other generator costs, we model three potential pathways for federal policy: (1) the status quo, which assumes no new federal initiatives through 2031; (2) moderate and aggressive (national or regional) RPSs; and (3) carbon taxes that vary in timing and amount. The model assesses the impact of these policies on competition between electricity generators using a range of output variables, including the cost of electricity, emissions of carbon dioxide (CO_2), retirement and construction trends for generation resources, and dispatch rates of generation technologies. We analyze conditions in four regional electricity markets with distinct starting generation portfolios, demand profiles (that differ seasonally and diurnally), wind and solar resources, and fuel costs. Our results provide new insights into the competitive barrier that low gas prices represent for renewables, the superior efficacy of carbon taxes (even at low rates) over RPSs, and the singular competitive advantage renewables enjoy by virtue of having near zero marginal costs.

1. Introduction

Scholars, policymakers and managers of electricity markets have long grappled with the tradeoffs and tensions associated with making energy simultaneously reliable, affordable, and clean. These tensions lie at the heart of debates over energy and environmental policy, and are exacerbated by two policy trends that are transforming electricity markets in fundamental ways.

One trend is toward more competition and market pricing in electricity markets. Beginning in the mid-1990s, a series of orders issued by the Federal Energy Regulatory Commission (FERC) (1) finally broke utilities' monopoly over access to the transmission grid, (2) permitted competition and market pricing in wholesale power sales, and (3) encouraged utilities to form so-called independent system operators or regional transmission organizations (collectively referred to as "ISOs") to manage transmission grids and oversee newly competitive and active regional wholesale power markets. (FERC, 1996, 2000). In response, a significant minority of states (including most of the Northeast, Texas and California) restructured their retail electricity markets in similar ways. As a consequence, there now exist robust, competitive regional wholesale power markets covering most of the country outside of the southeast and mountain west. Electric generation plants, formerly guaranteed a positive return on investment under the old regulated system, now compete on price within these competitive regional markets.

The second trend, driven by a confluence of market forces and policies, is toward greener forms of electricity generation that are supplanting coal-fired power and producing significant environmental benefits. The costs of generating electricity from natural gas-fired power plants, wind turbines and solar photovoltaics have fallen sharply, making coal-fired power much less competitive. These technologies have been given a competitive edge by a suite of federal, state and local policies, including federal tax incentives for investing in wind and solar projects, the Clean Power Plan and other EPA rules developed under the Obama Administration, state renewable portfolio standards (RPS) that set minimum requirements for the percentage of retail sales from renewable sources, state and regional carbon markets, and numerous other state and local initiatives. (DSIRE, 2017; Adelman and Spence, 2017). These developments are also impacting the longstanding scholarly debate over the optimal policies for decarbonizing energy markets, which has been dominated by proponents of carbon taxes (e.g., Pigou, 1920; Baumol and Oates, 1988) and RPSs (e.g., Carley et al., 2016; Davies, 2010). Increasingly, analysts believe that state and local policies will continue to drive rapid growth in renewable generation and that ultimately the remarkable declines in the costs of wind and solar power will make government incentive programs unnecessary. Others see state policies as an effective way to build support for stronger policies like a federal carbon tax (Meckling et al., 2015).

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The interaction of these trends—that is, of market competition with policies designed to promote green energy—has been the subject of numerous studies. Conventional wisdom says that inexpensive natural gas in the United States has taken market share from coal-fired generation, and the data seem to bear this out. (EIA, 2017a). On the other hand, higher penetration of renewables might further harm coal's position in competitive markets because the spot price of electricity should track the marginal costs of production. Recent analyses of the effect of renewables on prices in Texas (Zarnikau, 2011), Italy (Clò et al., 2015), Australia (Forrest and MacGill, 2013), and Germany (Tveten et al., 2013) offer some support for this hypothesis, as have climate and greenhouse gas emissions models offered by Zhang et al. (2015) and Shearer et al. (2014), respectively. Indeed, scholars have worried about the historic cost advantage enjoyed by fossil fuels and the phenomenon of "carbon lock in"—the notion that fossil generation, once built and paid for, will deter investment in renewables. (Unruh, 2000; Dahowski and Dooley, 2004; Davis, 2010). However, some argue that changes in American electricity markets are weakening carbon lock-in (Carley, 2011), particularly considering that the costs of wind and solar have fallen so sharply in the last two years (EIA, 2017b; Lazard, 2017).

We examine the interaction between price competition and policy in four ISO markets by modeling the economic dispatch of generation technologies and the evolution of generation resources over a fifteen year period beginning in 2016. Using a representative range of forward prices for natural gas and other generator costs, we model three potential pathways for federal policy: (1) the status quo, which assumes no new federal initiatives through 2031; (2) moderate and aggressive RPSs; and (3) carbon taxes that vary in timing and amount. The model assesses the impact of these policies on competition between electricity generators using a range of output variables, including the cost of electricity, emissions of carbon dioxide (CO_2), retirement and construction trends for generation resources, and dispatch rates of generation technologies. We analyze conditions in four broadly representative regional electricity markets with distinct starting generation portfolios, demand profiles (that differ seasonally and diurnally), wind and solar resources, and fuel costs. Our results provide new insights into the competitive barrier that low gas prices represent for renewables, the superior efficacy of carbon taxes (even at low rates) over RPSs, and the singular competitive advantage renewables enjoy by virtue of having near zero marginal costs.

2. The model

Our analysis uses an adaptation of the Cuevas (2016) Excel model,[1] an economic optimization algorithm that selects the lowest-cost option for electricity generation in two stages: (1) hourly dispatch of generation technologies, and (2) retirement or construction of generation resources when necessary to achieve the least-cost mix. More precisely, it uses cost projections for the generation technologies in each ISO to estimate both the number of hours that available classes of generating technology are dispatched and the price of wholesale power during those hours. For each class of generation technology, the dispatch estimates are then used to determine whether to close individual generation units (which vary in size by technology) that are not economically viable or to build new units needed to serve projected demand. This recursive framework approximates state-of-the-art models used by electric utilities, such as Plexos and Aurora (Mann et al., 2016).

[1] The original model was developed by Pedro Cuevas, a graduate student at the University of Texas at Austin, and focused on the Texas electricity market. We are greatly indebted to John C. Butler at the University of Texas McCombs School of Business, whose Excel programming expertise allowed us to adapt the model for our analysis and to apply it to the other three regional markets studied here. We benefited from John's programming assistance throughout this analysis, as well as from the suggestions and comments of University of Texas faculty Jim Dyer and Ross Baldick.

Using this approach, we ran a series of 15-year scenarios in four ISO markets: California ISO (CAISO), the Electric Reliability Council of Texas (ERCOT), ISO New England (ISO NE), and the Midcontinent ISO (MISO). At the highest level, the model calculates hourly market-wide prices for wholesale electricity sequentially in each ISO ignoring transmission constraints and sub-regional differences in electricity generation and demand. By placing each generation source in direct competition with all others in the system, the model reduces the number of calculations required and simplifies them. As a result, the security-constrained least-cost dispatch ("SCED") of existing generating units can be determined simply by selecting the generation unit with the lowest marginal cost. The algorithm has the following functional form:

$$min \mathrm{AAG}_{n,t}\left(\sum_{t=1}^{T}\sum_{n=1}^{N} MP_t \times AAG_{n,t}\right)$$

Subject to:

$$\sum_{n=1}^{N} AAG_{n,t} = D_t, \qquad \forall\ t$$
$$0 \le AAG_{n,t} \le MG_{n,t} \qquad \forall\ t, \forall\ n \tag{1}$$

where N is the total number of power plants, T is the total number of hours in the generation window (8760 h annually), MP_t is the market price in period t, $AAG_{n,t}$ is the total generation produced by power plant n during period t, $MG_{n,t}$ is the maximum generation potential for power plant n during period t, and D_t is the demand during period t. Typically, MP_t is the cost of the most expensive unit dispatched but the model evens out price spikes as described further below. The second constraint merely limits generation to the maximum capacity of each power plant.

We make additional simplifying assumptions about renewable capacity factors, which were approximated using data from published studies, and technological constraints. It ignores bulk power transfers between regions; while a small portion of each region's energy mix, power imports (and exports) can affect regional dispatch decisions. Most importantly, limits on generating-unit ramp rates are ignored, which allows power plants to be dispatched and switched off hourly. (Pouret and Nuttal, 2018). The relaxation of these constraints excludes consideration of start-up costs in the economic dispatch rule reflected in (1). Demand is therefore satisfied hour by hour ignoring unit commitments in the previous or future hours and any otherwise applicable minimum run times. These omissions can cause the model to under- or over-estimate thermal generation because plants may be switched off and on more frequently than real-world condition would permit. While these assumptions undoubtedly cause the model to depart from real-world dispatch patterns on an hour-by-hour basis, aggregated annually the results of our simulation are consistent with dispatch and capacity decisions generated using more complex, industry-standard models.

The model combines power plants into technology classes that are each managed as one modular unit. Each class of plant is further subdivided into pre-existing plants and new plants (those constructed during the model run), effectively doubling the number of classes. The model assigns a single set of cost and value data, including levelized costs of electricity (LCOE) and levelized avoided cost of energy (LACE), to each plant within a subcategory for each ISO region. The existing technology categories used in the model are listed below:

- *Wind*: Two classes, one of land-based and one of off-shore wind generation.
- *Solar Photovoltaic (PV)*: single class limited to utility-scale PV systems.
- *Hydroelectric*: single class for hydroelectric generation regardless of MW.
- *Biomass*: single class for biomass generation.
- *Nuclear*: single class for nuclear generation.
- *Fuel Oil*: single class for oil-fueled power plants.

- *Coal***:** single class for coal generation; plants were not divided by type of coal.
- *Noncycling Gas*: single class for base-load or high capacity factor gas plants.
- *Cycling Gas*: single class for gas plants used intermittently to supply peak loads.

Historical hourly load data from each of the four regional markets were used to simulate hourly changes in demand. Specifically, the hourly ISO loads in 2016 were set as equal to their hourly loads in 2015; the load data were then updated each year under the assumption that off-peak load (hours 0–7 and 19–24) would grow annually by 0.2% and that on-peak load (hours 8–18) would grow by 0.75%. Our SCED dispatch algorithm orders the classes of power plants from lowest to highest variable costs (operating, maintenance and fuel costs) and satisfies demand using this ranking system for each hour. To estimate variable costs, we assume that the relative efficiencies of different generation technologies do not change within a calendar year, but they can vary from year to year. Similarly, we vary fuel prices annually according to forecast data and other publically available projections. To account for scarcity pricing during highly stochastic periods of scarcity, such as extreme weather events, unexpected generation outages, or grid failures, the model used historical hourly price data from each ISO to estimate the number of such scarcity pricing hours; the model then imposed a schedule of scarcity prices based upon that same historical data for each ISO, rather than deriving electricity prices from the marginal price of the last plant dispatched. This approach simulates scarcity prices, which depart from marginal costs. Further details about these aspects of the model are described in Appendix.

The algorithm we use to determine retirements and capacity additions compares LACE with unit-level operations and maintenance costs, both fixed (FO&M) and variable (VO&M). This approach recognizes that the inequality $LACE < LCOE$ should not determine whether a unit is retired, as managers will operate a plant so long as $FO\&M + VO\&M < LCOE$. However, when $LACE < FO\&M$, a unit would be operating at a loss and it would be economically rational for managers to shut it down. For additions of new capacity, the model selects the plant with the highest net value, defined here as the difference between LACE and LCOE, to meet growing demand or to replace retired units. Importantly, the model restricts "net value" to an *annual* assessment of changes in demand, capital costs, O&M costs, subsidies, and fuel costs. This makes the model temporally myopic—retirements and expansions are based solely on revenue and costs in the relevant year, as opposed to the forecast life of the plant.

To accommodate short-term capacity shortages, we incorporated one additional simplifying element into the model: a backup "Big M" technology that fills in short-term gaps between supply and demand. Given ongoing concerns about the ability of price signals to ensure supplies at high levels of reliability, this is an important assumption, albeit one used commonly in models of this type. (Milligan et al., 2016). The generating costs associated with Big M (set at $1 above the most expensive available technology) are not factored into the annual costs derived by the model; instead, they signal the high value of the last units of generation and, in doing so, create an incentive for construction of new capacity. In other words, the number of hours that are served by Big M affects the modeled market clearing price, representing the costs the system avoids by building new generation.

The model's simplifying assumptions reflect a conscious choice to strip away certain real-world characteristics of electricity markets in order to illuminate fundamental competitive market dynamics in the generation sector. It is widely recognized, for example, that the availability of transmission often determines whether and where new power plants are built. Yet, the cost of transmission accounts, on average, for less than 15% of the total cost of electricity in the U.S., and the rate-limiting barriers to new transmission are principally regulatory and political, not economic. (Flares and King, 2016). Thus, while undoubtedly important, the model's omission of transmission constraints is consistent with our focus on understanding the economics of competition between generating resources in electricity markets. Similarly, this analysis does not attempt to model the provision of ancillary services. At first blush, this assumption would seem to bias dispatch predictions against traditionally dispatchable resources by omitting revenues they could earn in competitive ancillary service markets; but recently renewable resources and demand response resources have made substantial inroads into ancillary services markets, a trend that seems likely to continue. Indeed, integrating transmission, intra-hour ancillary services, and other grid reliability constraints into the model would increase the model's complexity and could yield analytically indeterminate results.

Thus, defining feature of the model is that it omits key sources of friction and inertia in electricity markets. For example, at short time scales, the absence of limits on ramp rates allows the cheapest generation source always to be dispatched. At longer time scales, the absence of grid-infrastructure, financing, and regulatory constraints allows the cheapest source of new generation always to be selected. In addition, Big M provides a positive market signal for construction of new generation when there are significant shortfalls in generating capacity. Together, these simplifying elements accelerate the rate at which generators and new generation respond to market conditions, creating a temporally compressed, time-lapse picture of competitive market dynamics. This simplicity enables us to analyze market competition between generation technologies without the overlay of external structural and political constraints. Price competition is an increasingly prominent feature of American electricity markets, and some proponents of "decarbonizing" electricity markets see price competition between generators as crucial to their plans. (e.g., Johnson, 2010). In order to gain insight into the strength and direction of the competitive market forces under which electricity generators operate, and how different policy instruments can influence them, our model sacrifices some contextual realism.

3. The regions and scenarios modeled

We simulate the hourly dispatch and evolution of generation resources in CAISO, ERCOT, ISO NE, and MISO for the years 2016–2031. For each region, the simulations begin with the actual 2016 fuel mix and other data for that region. As reflected in the load profiles, fuel prices, and generation resources summarized in Table 1, these regional markets cover a range of market conditions and generation portfolios. For example, ISO NE has high natural gas prices and almost no renewable generation, while ERCOT has low natural gas prices and a higher percentage of renewable generation. By contrast, MISO's generation mix is almost 40% coal, while CAISO's contains almost none.

For each regional market, six federal policies were examined: a status quo scenario, which assumes the EPA's greenhouse gas regulation program under the Clean Power Plan will be abandoned and no new federal policies to address carbon emissions will be adopted; two

Table 1
ISO Load profiles, relative gas prices, renewable resources, and 2016 installed capacity by technology.

ISO Characteristic	CAISO	ERCOT	MISO	ISO NE
Load Profile Variability	Low	High	Moderate	Moderate
Price of Natural Gas	Low	Low	Moderate	High
Solar Resource	Excellent	Excellent	Modest	Modest
Wind Resource	Excellent	Excellent	Excellent	Modest
Coal/Oil-Fired Capacity	1%	21%	37%	26%
Gas-Fired Capacity	54%	55%	40%	45%
Nuclear Capacity	3%	6%	8%	14%
Hydro Capacity	18%	1%	1%	11%
Renewable Capacity	22%	13%	13%	2%
Other Capacity	2%	4%	1%	2%

federal RPS scenarios, one moderate and one more aggressive; and three federal carbon taxes that vary in timing and magnitude. The RPSs were simulated by forcing the model to build sufficient renewable capacity, prioritizing the cheapest option, to meet statutory targets annually. The moderate RPS started at 5% in 2016 and rose by 5% every other year to reach 30% by 2031. The aggressive RPS started at 5% in 2016 and rose by 5% each year to reach 50% by 2031.[2] The carbon tax was incorporated directly into annual fossil-fuel generation costs in three variants: (1) a flat-rate tax set at $25/ton of CO_2 beginning in 2016; (2) a moderate-delayed carbon tax initiated in 2021 at $10/ton of CO_2 and increased every second year by $5 to a maximum of $35/ton of CO_2 in 2031; and (3) an aggressive-delayed carbon tax initiated in 2021 at $40/ton of CO_2 and stepped up to $50/ton of CO_2 in 2027.

To accommodate a range of price projections for renewables, we ran each of the six policy scenarios with moderate and low price curves for wind and solar generation, using the following cost schedules.

- Moderate Solar: 4% rate of decline beginning at $1100/kW in 2016 and ending at $812/kW in 2031;
- Low Solar: 10% rate of decline from 2016 through 2020 followed by a 4% rate of decline through 2031, with a starting price of $1100/kW and an ending price of $681/kW;
- Moderate Onshore Wind: 3% rate of decline beginning at $1250/kW and ending at $996/kW;
- Low Onshore Wind: 5% rate of decline beginning at $1250/kW and ending at $855/kW;
- Moderate Offshore Wind: 4% rate of decline beginning at $1500/kW and ending at $1108/kW;
- Low Offshore Wind: 8% rate of decline beginning at $1,500k/W and ending at $813/kW.

Similarly, given the importance and uncertainty of future natural gas prices, each of these twelve scenarios was run using low, moderate, and high natural gas price forecasts, which expanded the number of scenarios to 36 for each regional market, for a total of 144 in all. In each scenario, gas prices started at roughly $2.50/MMBtu in 2016 and increased monotonically at different rates, with the low-price scenario rising to $4.45/MMBtu in 2031, the moderate-price $6.76/MMBtu, and the high-price $8.25/MMBtu. The price assumptions and source data are provided in the online supplement. Table 2 summarizes the expected direction of the correlations between the price/policy scenarios we modeled and the economic dispatch of the generation technologies.

For each scenario, we examine four principal categories of output variables: (1) the wholesale price of electricity; (2) average regional emissions rates for CO_2 and conventional pollutants; (3) quantities of retired and new generation capacity; and (4) operational capacity factors for each technology—that is, the percentage of time annually that a plant generates electricity. As a measure of how often each technology is being dispatched, capacity factors provide a direct measure of the relative competitiveness and value of each generation technology. We focus in particular on changes in the capacity factors for coal-fired and nuclear power plants because of (i) current concern among policymakers about their importance to grid reliability, and (ii) their historic role as base-load technologies built to operate at very high capacity factors. All of the input variables used in the model are provided in the online supplement to the paper.

[2] Because state RPSs vary widely in their stringency, and are constantly changing, it is prohibitively difficult to try to model individual state RPSs. A few states have established 50% renewable goals at specified points in the future. Some states have no RPS at all. Our two national RPS scenarios were intended to subsume the full range of stringency and aspirations among state RPSs — ranging from 5% to 50%. It may be politically unrealistic to assume that any RPS would move from very modest goals to very aggressive goals in 15 years, but, we do so in order to explore the efficacy of this policy instrument as a tool for forcing decarbonization. We ignore local carbon trading regimes and other state renewables policies in our model as well, in order to focus more directly (and tractably in our model) on the effects of our two policy instruments of interest.

Table 2
Expected correlations between scenario inputs and principal generation technologies.

Price or Policy Variable	Coal Plant	Gas Plant	Renewables	Nuclear Plant
Price of Natural Gas	Positive	Negative	Positive	Positive
Price of Renewables	Positive	Positive	Negative	Positive
Stringency of RPS	Negative	Negative	Positive	Negative
Value of Carbon Tax	Negative	Negative	Positive	Positive

4. Results and discussion

Tables 3a and 3b below display the values in 2031 by region of several key output variables for each of the six policy scenarios, but for only a small subset of the 144 simulations that we conducted. For the status quo policy rows, the “low,” “moderate,” and “high” columns in the table correspond to the low, moderate, and high price forecasts for natural gas. For rows corresponding to the RPS and carbon tax scenarios, the meanings of these labels change. For the RPS scenarios, the values displayed in the “moderate” and “high” columns correspond to the moderate and aggressive RPS policies. For the carbon tax scenarios, the values displayed in the “low,” “moderate” and “high” columns correspond to the flat-rate, moderate-delayed, and aggressive-delayed carbon taxes. Correspondingly, all of the outcomes in the table associated with the RPS and carbon tax scenarios are based on the moderate forward prices for natural gas.

The broad trends observed in Tables 3a and 3b track the relationships predicted in Table 2, with some notable exceptions. The results are also generally consistent across the ISOs apart from divergences associated with regional differences in natural gas prices, load profiles, and initial generation portfolios. As discussed more fully in the subsections below, the most striking results involve countervailing shorter- and longer-term dynamics, most notably the influence of high gas prices on renewable capacity additions and the superiority of carbon taxes over RPSs in reducing carbon emissions.

4.1. Price and policy impacts on generation resources

4.1.1. Low gas prices limit construction of renewables

The impact of low-cost natural gas prices on renewables has been a flashpoint in the debate over decarbonizing the electricity sector. Proponents of gas generation have argued that it is a valuable bridge technology between coal-fired generation and various forms of zero-emissions technologies. We find strong support for the view that low natural gas prices—below $3.50/MMBtu through 2023 and below $4.50/MMBtu through 2031—inhibit construction of new renewable capacity. In the status quo scenarios, renewables capacity doubled to tripled in CAISO, MISO and ISO NE and increased by a factor of nine in ERCOT between the low- and moderate-price gas scenarios (Table 3a). This effect is therefore observed in all four markets regardless of the degree to which gas generation is the dominant generation source. The effect is significantly reduced, however, at or above moderate gas prices—renewable capacity increased by less than 30% between the moderate- and high-price gas scenarios in all four ISOs. Overall, gas prices have a substantial impact on renewable capacity in all four markets.

4.1.2. In the longer-term, high natural gas prices are associated with reduced capacity factors for coal-fired generation

Despite the dramatic impact that low-cost natural gas has had on coal-fired power in the United States, we find that longer-term low gas prices preserve coal-fired capacity (and generation) by deterring the entrance of renewables. The model simulations reveal that while low natural gas prices drive down levels of coal-fired generation in the near-term, they are not low enough to cause closure of significant coal-fired

Table 3a
Carbon emissions in 2031, new plant constructed, & prices.

ISO	Scenarios	CO_2 Emissions (lb/MW h)			Renewables Added (MW)			Price of Electricity ($/MW h)		
		Low	Moderate	High	Low	Moderate	High	Low	Moderate	High
ERCOT	Status Quo	946	828	744	5000	40,000	49,500	42	46	49
	RPS		828	714		40,000	50,000		46	42
	Carbon Tax	257	242	217	73,000	76,500	81,500	53	53	55
	Status Quo	557	346	299	10,000	31,500	38,000	40	48	51
CAISO	RPS		346	346		31,500	31,500		48	48
	Carbon Tax	291	271	202	39,000	42,000	46,000	51	52	53
	Status Quo	1434	1312	1230	12,000	38,000	49,500	40	45	47
MISO	RPS		1210	806		49,000	95,000		42	32
	Carbon Tax	247	571	196	140,000	138,500	162,000	54	51	61
	Status Quo	539	347	294	12,000	23,000	26,500	42	51	55
ISO NE	RPS		347	347		23,000	23,000		51	51
	Carbon Tax	238	262	200	27,500	28,500	30,500	54	55	56

Table 3b
Nuclear & thermal capacity factors and percent coal generation in 2031.

ISO	Scenario	Nuclear Capacity Factor			Thermal Capacity Factor			Coal Capacity Factor		
		Low	Moderate	High	Low	Moderate	High	Low	Moderate	High
ERCOT	Status Quo	90%	88%	85%	40%	30%	26%	9%	10%	8%
	RPS		88%	84%		30%	26%		10%	8%
	Carbon Tax	71%	69%	65%	22%	21%	20%	0%	0%	0%
	Status Quo	90%	78%	72%	37%	25%	21%	0%	0%	0%
CAISO	RPS		78%	78%		25%	25%		0%	0%
	Carbon Tax	71%	68%	64%	20%	19%	19%	0%	0%	0%
	Status Quo	90%	90%	90%	44%	42%	39%	25%	22%	20%
MISO	RPS		90%	84%		39%	25%		19%	10%
	Carbon Tax	72%	72%	64%	21%	17%	19%	0%	6%	0%
	Status Quo	90%	81%	75%	28%	19%	17%	2%	1%	1%
ISO NE	RPS		81%	81%		19%	19%		1%	1%
	Carbon Tax	72%	70%	65%	12%	16%	14%	0%	1%	0%

generation capacity. Accordingly, as gas prices rise over time, coal-fired generation rebounds but the higher gas prices are not sufficient to stimulate dramatic increases in new renewable capacity. By contrast when gas prices rise faster and higher, coal-fired generation may be initially more competitive against gas-fired generation, but longer-term it is displaced by very large additions of renewable capacity as gas prices escalate. Over the 15-year period we modeled, the dramatic growth of renewables had the greatest impact on coal-fired generation.

4.1.3. High natural gas prices also reduce the capacity factors for nuclear-powered generation

This effect is also driven by the large increases in renewable generation associated with high gas prices. A critical factor here is the low marginal costs of nuclear power, which make it less vulnerable to low gas prices than to near-zero marginal cost renewables. In essence, while low near-term natural gas prices can reduce the capacity factors of nuclear power plants directly, the addition of new renewable capacity when natural gas prices are high represents a far greater threat to nuclear power in the long run. Under high gas price scenarios, the model projects that capacity factors for nuclear power in 2031 will decline by roughly 15% relative to current levels in CAISO and ISO NE, both of which are dominated by gas generation (see Table 3b). This effect is attenuated in ERCOT and completely absent in MISO because coal-fired generation buffers, to different degrees, the impact of high gas prices on the wholesale market price of electricity.

4.1.4. RPSs have little effect on capacity factors for base-load generation, except in MISO

Regardless of gas price, we find that the moderate RPS has no effect on the capacity factors for nuclear-powered generation and that the aggressive RPS impacts nuclear capacity factors only in MISO. The impacts of RPSs on fossil-fueled generation are similarly limited but more variable across regions. At moderate gas prices, the moderate RPS had little or no effect on capacity factors for fossil-fueled generation (3% in MISO and no effect in ERCOT, CAISO, and ISO NE), while the aggressive RPS resulted in somewhat lower capacity factors (7% in MISO and 0–2% in ERCOT and CAISO).[3] Retirements of fossil-fueled power plants follow a similar pattern to the impacts observed on capacity factors. A moderate RPS generates no additional retirements in ISO NE and CAISO, and it is actually associated with a 2.5 and 7.5 GW decrease in retirements in ERCOT and MISO, respectively. An aggressive RPS causes essentially no additional retirements in CAISO and ISO NE, and counterintuitively (because less new natural gas capacity is built) further decreases in retirements of 3.5 and 8.5 GW, respectively, in ERCOT and MISO. These results suggest that the influence of natural gas prices on fossil-fueled generation can override the effects of RPSs. In short, outside regions such as MISO where coal-fired generation attenuates the influence of high gas prices, RPSs are relatively ineffective at stimulating construction of new renewable generating capacity when gas prices are moderate or higher. We find that only an aggressive RPS (in the range of 50% renewables) materially changes thermal capacity factors and future generation portfolios, but their efficacy depends strongly on the amount of coal-fired generation in the region.

4.1.5. Carbon taxes reduce the capacity factors for base-load generation

As expected, carbon taxes reduce capacity factors for coal-fired generation, although the strength of the relationship varies by region.

[3] ISO NE is a special case because the capacity factor for fossil-fueled generation increased by 4% points under the aggressive RPS. We ascribe this to the lower level of new natural gas fired-power plants constructed under this scenario, which leads to higher capacity factors for the existing fossil-fueled power plants.

Surprisingly, the model also predicts that the capacity factors of nuclear power plants will *decline* by 12–26% points beyond the declines associated with moderate natural gas prices, due to the same dynamic at work between gas prices, renewable entry, and coal-fired generation. The declines vary substantially across the regional markets because the sensitivity of nuclear power capacity factors to natural gas prices varies, as demonstrated in the preceding discussion, by region from 7% to 14% in CAISO to 18–26% in MISO. It is possible that this result is an artifact of the model's assumption that nuclear and renewable generators are dispatchable hourly based on marginal costs. Nonetheless, this is an alarming result for the nuclear industry, which has been a vocal advocate of carbon taxes on the assumption that they would make nuclear power more competitive against fossil-fueled generation. That intuition is undoubtedly true in the near-term, but carbon taxes bring higher prices, which in turn stimulate the construction of zero-marginal-cost renewable generation that represents a far greater threat to nuclear power than historically low natural gas prices.

4.2. Price and policy impacts on average emissions rates of CO_2 and conventional pollutants regionally

4.2.1. High natural gas prices reduce emissions rates for CO_2

Once again, while low gas prices displace some coal-fired generation in the near term, the incentive to construct new renewable generating capacity created by high gas prices, particularly in markets dominated by gas generation, ultimately leads to lower CO_2 emissions. These dynamics are reflected in the quantity of renewables constructed, retirements of fossil-fueled power plants, and capacity factors for fossil-fueled and nuclear-powered generation. In the absence of external barriers to entry and reliability concerns, the rivalry between natural gas and coal is ultimately replaced by the competition between wind, solar, nuclear-powered, and natural gas-fired generation.

Interestingly, this also holds true for emissions of conventional pollutants (sulfur dioxide and nitrogen oxides) in ISO NE, CAISO, and MISO, but not in ERCOT. The effect is strongest in MISO, which has a very large coal-fired power fleet; there the entry of renewables is displacing coal rather than gas, with correspondingly dramatic effects on conventional pollutants. This is a striking finding, because while coal-fired power plants emit about twice as much CO_2 as gas-fired plants, they emit much larger multiples of conventional pollutants; and those conventional pollutant emissions tend to dominate EPA and other estimates of the environmental and health harms of power plant emissions. By contrast, in ERCOT, where both gas-fired and coal-fired generation fleets are robust and compete directly, emissions of conventional pollutants *increase* with natural gas prices; this is because very low gas prices shut coal out of the market in the early years of the simulation in ways that exceed the gains from renewables later. Thus, where natural gas and coal are in robust competition in our model (ERCOT), inexpensive gas crowds out coal; but where coal is a minimal part of the generation mix (CAISO and ISO NE) or a very strong part of the mix (MISO), inexpensive natural gas delays entry by the renewable generation that ultimately crowds out the lion's share of coal plants.

4.2.2. Under most scenarios RPSs have relatively modest impacts on emissions rates for CO_2

Consistent with the limited impacts of RPSs on existing and new generation capacity, a moderate RPS does not lower CO_2 emissions rates below the status quo in regions other than MISO when gas prices are moderate or higher; moreover, even when gas prices are low, the effect is likely to be small (0–10% in these regions). MISO is again an outlier because it has such a large fleet of coal-fired generation; there, the moderate and aggressive RPSs reduced CO_2 emissions rates by as much as 16% (low gas prices) and 38–43% (low to moderate gas prices), respectively. These results reinforce the importance of policymakers considering local generation resources when selecting policies.

4.2.3. Under all three scenarios for gas prices, carbon taxes cause dramatic reductions in emissions rates for CO_2

The lowest moderate-delayed carbon tax (starting at \$10/ton of CO_2 in 2021 and rising to \$35/ton of CO_2 by 2031) yielded far greater reductions in carbon emissions than the aggressive RPS in all four regional markets. With the exception of MISO, in which the emission rates dropped from roughly 1300–570 lb/MW h, CO_2 emissions dropped below 300 lb/MW h in all of the scenarios with carbon taxes. This result is striking for two reasons. First, the moderate-delayed tax rates are at the lowest end of the range commonly discussed by policymakers. Second, the emissions rates the model projects for scenarios with carbon taxes are extremely low, particularly in comparison to the guidelines under EPA's embattled Clean Power Plan, which sets goals for the relevant states of roughly 500–1200 lb/MW h. These rates are 2–3 times higher than the CO_2 emissions the model projects in each region except MISO. The model results reaffirm the twin virtues of carbon taxes—they increase the economic incentives for new renewable capacity (by raising wholesale prices of electricity), and they dramatically impact the competitiveness of fossil-fueled generation. This double dividend is evident in the declines observed for thermal capacity factors in ERCOT and MISO, which drop by 8–25% under carbon taxes relative to the status quo, and much more dramatically for coal-fired generation, which is effectively shut down in both ISOs apart from the moderate-delayed carbon tax scenario in MISO.

4.3. Indirect interactions between natural gas prices and policy instruments

4.3.1. High gas prices do not always result in the lowest emissions rates for CO_2

We find that CO_2 emissions rates in ERCOT under the aggressive RPS scenarios appear to contradict the negative correlation we otherwise observe between natural gas prices and CO_2 emissions rates. The emissions rates in 2031 for the low, moderate, and high price curves in ERCOT for natural gas are 626, 713, and 730 lb/MW h, respectively.[4] We believe this occurs in ERCOT because (1) the aggressive RPS capacity requirements are sufficient to offset the barrier to new renewable generation associated with low gas prices, and (2) low gas prices allow gas-fired power plants to displace large quantities of coal-fired generation. Similar to the distinctive dynamics in MISO (discussed above), this phenomenon illustrates how in a competitive market the particular balance of coal- versus gas-fired generation, gas prices, and policies interact to determine outcomes. ERCOT occupies a “sweet spot” between CAISO and ISO NE, which have very little coal-fired generation, and MISO, which has the largest coal-fired generation capacity of the four regions. In ERCOT natural gas prices still determine wholesale electricity market prices, which explains why RPSs are effective when gas prices are low, but there is enough coal-fired capacity that low gas prices still produce large declines in coal-fired generation and concurrent reductions in CO_2 emissions. In short, an aggressive RPS in ERCOT can exploit the benefits of low gas prices (reduced coal-fired generation) while neutralizing their downside (diminished incentives for adding new renewable generating capacity).

4.3.2. Carbon taxes interact with gas prices and generation portfolios in similarly complex and localized ways

ERCOT is also atypical in that under a moderate-delayed carbon tax, we find that moderate gas prices (rather than high ones) result in the lowest CO_2 emissions rate (242 lb/MW h), with low gas prices a close second (318 lb/MW h) and high gas prices third (416 lb/MW h). Under a moderate carbon tax, high gas prices more than offset the lower

[4] It is interesting note that in MISO there is essentially no difference in the CO_2 emissions rates associated with RPSs, whether moderate or aggressive, under scenarios with low and high gas prices. This shows again how the existence of significant coal-fired generation capacity buffers CO_2 emission from natural gas prices.

carbon taxes paid by gas-fired power plants relative to their coal-fired competition (which has roughly double the CO_2 emissions rates). This means that when gas prices are high, new renewable generating capacity may displace natural gas plants rather than coal-fired generation. By contrast when gas prices are low, coal-fired generation is displaced first, but this comes at a cost—reduced additions of new renewable generation capacity. In ERCOT, this countervailing effect more than offsets the CO_2 emissions reductions associated with gas-fired plants displacing coal-fired generation. With a moderate-delayed carbon tax, 56,000 MW of renewable generating capacity was constructed when gas prices were low versus 76,500 MW when gas prices were moderate. Accordingly, where coal generating capacity is substantial but not dominant, carbon taxes are most effective when natural gas prices are moderate.[5] Under these conditions, natural gas can still compete with coal but it is not so competitive that it dramatically impacts additions of new renewable generating capacity. This is reflected in the modest difference (76.5 versus 80.5 GW) in renewables constructed between moderate and high scenarios for gas prices. As a result, the impact of gas prices on federal policies will not be uniform regionally and is sensitive to the quantity of coal-fired generation capacity in each market.

4.3.3. *Delaying carbon taxes can significantly impact their effectiveness*

This phenomenon is most pronounced in MISO, where the moderate-delayed carbon tax results in CO_2 emissions rates that are double those for the other two carbon tax scenarios, but it is also evident in ISO NE (*see* Table 3a). About 29 GW of coal-fired capacity is retired in MISO under the moderate-delayed scenario versus 71.5 and 72.5 GW under the flat-rate and aggressive-delayed carbon tax scenarios. We believe this disparity arises because gas prices gradually rise over the fifteen-year period of the model simulations. Thus, the timing of a carbon tax matters—particularly when it reaches roughly \$20/ton of CO_2—because its efficacy is affected by the prevailing price of natural gas. This dynamic is clearly evident in the model scenarios: much more coal-fired capacity retires in MISO by 2024 under the flat-rate and aggressive-delayed scenarios (66.5 and 56.5 GW, respectively) than under the moderate-delayed scenario (27.5 GW). For the flat-rate and aggressive-delayed scenarios, the combination of low gas prices and a robust carbon tax precipitate early and widespread retirements of coal-fired generation. However, by the time that the moderate-delayed carbon tax reaches \$20/ton of CO_2, the higher gas prices allow the existing coal-fired fleet to operate at greater capacity factors that produce higher CO_2 emissions rates regionally. Thus, although the carbon taxes are generally unaffected by gas prices, MISO demonstrates that the wrong combination of timing, coal-fired generating capacity, and gas prices can undermine their efficacy.

5. Conclusions and implications for policy

We employ a simple two-step model of generation dispatch and capacity additions/retirements in a frictionless electricity market to reveal several surprising insights into the interplay of federal policies and market conditions. In competitive electricity markets, we find that (1) renewables pose a much greater threat to the viability of base-load generation in the longer-term than natural gas-fired generation; and (2) when gas prices set market prices, they also determine the economics of renewables, and thereby the volume of new renewable capacity that enters the market. Together, these two phenomena produce the counterintuitive result that higher gas prices are correlated with lower emissions, lower capacity factors for coal-fired and nuclear power, and faster growth in renewable generation. For all the damage inexpensive gas has done to coal's market share in the past, as we look forward it appears that the most significant impact of inexpensive gas is likely to be limiting entry of renewables.

With respect to federal polices, our results provide new grounds for favoring carbon taxes over RPSs; although, the disparity in efficacy is reduced in markets with substantial coal-fired generation. The limitations we find in RPSs moving forward are particularly noteworthy given their widespread adoption at the state level. We find that in a contest between an RPS and carbon tax (or an equivalent carbon trading market), the latter wins hands down in leveraging the competitive dynamics of wholesale electricity markets. Our analysis also highlights the importance of taking into account regional differences in generation portfolios, which we find can dramatically alter the effectiveness of federal policies. This suggests the need for caution in the formulation of federal policies that might have difficulty accommodating regional variation, and the potential superiority of a cooperative federalism approach under which regional entities (like ISOs) formulate their own means to achieve national goals.

Although not discussed above, prices of electricity generation in all of our modeled scenarios were projected to remain in the range of \$40–60/MW h through 2031, with most concentrated around \$50/MWh. This result suggests that a shift away from fossil-fueled generation can be achieved cost effectively and at rates that differ only modestly from the status quo. However, this conclusion comes with important caveats. As noted previously, the model ignores constraints associated with transmission, financing, regulation, and grid reliability. Thus, whereas the model presumes that short-term supply gaps can be filled costlessly and quickly, in real-world electricity markets providing reliable generation may entail significant delays and costs, as traditionally non-dispatchable renewable generation becomes a large share of generation resources. Furthermore, as renewables penetration increases, the maintenance of a reliable supply will require the availability of fast-ramping resources to address decreases in wind and solar generation; natural gas-fired generation may be the most economic fast-ramping resource available. Similarly, while carbon taxes are effective policy instruments for idealized competitive markets, an RPS may be superior at overcoming external political or financial barriers to entry for renewables. (Meckling et al., 2015).

Thus, while the model cannot and should not be interpreted as addressing these broader questions, its relative simplicity enables us to explore competition in wholesale electricity markets and the influence of policies under broad range of potential scenarios. Using standard estimates of the relative costs of generation technologies and a pared-down model of regional competition in electricity markets, the model exposes the limitations of current policies and the importance of longer-term trends. Most importantly, it demonstrates that (i) competition between natural gas- and coal-fired generation will become secondary to competition between natural gas-fired generation, nuclear power, and renewables as decarbonization of the electricity sector progresses; and (ii) carbon taxes are far more effective than RPSs at reducing carbon emissions in competitive wholesale electricity markets but at somewhat higher prices for electricity.

APPENDIX: Modeling electricity prices during gaps between supply and demand

An important element of the model not described above concerns the role of "Big M" in determining the number of hours each year when prices in each ISO are highest. Recall that Big M is a generic backup generation source that operates during short-term gaps between supply and demand. Under real-world conditions, these gaps would be associated with extreme weather conditions (storms, droughts, very high or low temperatures), transmission failures, unscheduled maintenance on major generation resources, or other unforeseeable disruptions. While such gaps are relatively infrequent, totaling fewer than 20 h in most

[5] This effect is not observed in ERCOT because it has a much lower amount, in both absolute and relative terms, of coal-fired generation than MISO. As a consequence, even under the moderate-delay carbon tax most of the coal-fired generation is retired by 2023. The effect is observed in ISO NE, albeit modestly, because it has both higher gas prices than the other regions and sufficient coal- and oil-fired generating capacity.

years, their brevity is offset by the revenue generated when prices spike. To put this in perspective, 20 h of generation when prices are above $1000/MWh is comparable to the revenue generated during 1000 or more hours at average off-peak rates. The disproportionate economic value of these periods requires that pricing of Big M hours be fairly calibrated to actual market conditions. However, it is precisely during such periods, when the portfolio of generation resources is disrupted, that the marginal price of power determined by demand is unlikely to be an accurate measure of electricity prices. To fill this gap we collected hourly market-price data from each ISO over several years to identify representative price spikes that could be used to set the price of electricity when Big M operates in the model.

The duration of the price data that we were able to obtain varied across the four ISOs. Specifically, while we were able to obtain six years of hourly price data for ERCOT, we were limited to four years for CAISO and ISO-NE, and to just three years for MISO. During each run, the model cycled between the available years of hourly price data when setting the cost of electricity during the hours that Big M was operational. Thus if we had data for 2013, 2014, and 2015, we would use the hourly price data for 2015 and then sequentially cycle through the price data for 2014 and 2013 after which the cycle would be repeated through year 15. This method was used exclusively for the few hours in which Big M operated, namely, when supply was assumed to be disrupted or demand was exceptionally high; otherwise, the clearing price of the marginal fuel determined the price of electricity during each hour.

It was also essential that the pricing for Big M take into account dynamic changes in the generation portfolio of each ISO over time. The model did this by setting the base year, 2016, as the neutral point for Big M's operational hours, such that subsequent increases or decreases in Big M's hours caused by retirements or additions of capacity were counted relative to the 2016 baseline. In other words, both the number of hours of high prices and the electricity prices themselves increased in response to retirements and, conversely, they both decreased when new capacity additions occurred. The model simulates these dynamic changes by selecting the historical price data further up or down the price stack depending on whether the number of hours that Big M operated in a given year was greater or less than the 2016 base year. Thus, if in the base year Big M operated for 15 h and in 2017 it operated just 10 h, the hours with the five highest prices would be omitted and the ten next-highest hours were used for the Big M hourly prices in 2017. However, if Big M operated for 20 h in 2017, we used a simple linear model (the average rate of increase in price for the 10 highest hourly prices) to extrapolate prices for Big-M from the historical price data up to an assumed cap of $9000/MW h. Through this modeling framework, Big M provided price signals for construction of new generation and its pricing responded annually to retirements and new capacity in each ISO over the course of the 15-year period that the model was run.

Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.enpol.2018.05.019.

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