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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).

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.

[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.