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Electricity price behavior and carbon trading: New evidence from California

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HIGHLIGHTS

- Presents new evidence on the California cap-and-trade (C & T) program on the state's day-ahead electricity prices.
- Explains the C & T program's effectiveness in reducing CO_2 emissions in the western portion of North America.
- Recommends expanding the C & T program's geographic scope to improve its effectiveness.

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ABSTRACT

The incidence of climate change policy is of great interests to economists, policy makers, producers and consumers. Using the daily market data for a 65-month period of 01/01/2011–05/31/2016, this empirical paper documents that the California Independent System Operator's day-ahead prices have a CO_2 premium approximately equal to natural-gas-fired generation's marginal cost of CO_2 emissions. This finding prevails in the six time-of-day periods developed to match the pricing periods used by the state's local distribution companies and the bilateral trading of wholesale electricity in the Western Interconnection, a large electricity grid serving the western portion of North America and a Mexican state. Our findings suggest that the California cap-and-trade (C & T) program is effective in internalizing CO_2 emission costs of the in-state natural-gas-fired generation. However, the program's economic efficiency is compromised by the unintended consequence of power laundering under inter-regional trading of wholesale electricity. While the program encourages the Pacific Northwest's hydro export that displaces California's natural-gas-fired generation, it also induces output increases by non-California coal- and natural-gas-fired generators in the Western Interconnection. Hence, reducing the overall CO_2 emissions in the Western Interconnection requires expanding the program's geographic scope to meaningfully address the global warming problem.

1. Introduction

Three transformative events have taken place in the world's electricity industry. The first event is market restructuring to introduce wholesale competition in Europe, North America, South America, Australia, New Zealand, and Asia [1–3]. Wholesale transactions occur via bilateral trading enabled by open transmission access and in centralized markets operated by an independent system operator based on the theory of locational marginal pricing [4–8]. Wholesale electricity market prices are highly volatile,[1] leading to extensive research in price behavior and dynamics, forward contracts and tolling agreements, derivatives and risk management, product differentiation, system operation and integrated resource planning [6,9–48]. Despite occasionally large price spikes, wholesale energy markets have insufficient incentive for generation investment, a problem remedied by capacity markets that can provide stable cash flows critical for financing new plant construction [49–54].

The second event is large-scale renewable energy development,

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[1] Wholesale electricity prices are inherently volatile due to: (a) daily fuel-cost variations, especially for the natural gas that is widely used by combustion turbines and combined-cycle gas turbines; (b) hourly weather-sensitive demands with intra-day and inter-day fluctuations, which must be met in real time by generation and transmission already in place; (c) planned and forced outages of electrical facilities; (d) hydro conditions for systems with significant hydro resources; (e) carbon-price fluctuations affecting thermal generation that uses fossil fuels; (f) transmission constraints that cause transmission congestion and generation re-dispatch; and (g) lumpy capacity additions that can only occur with long lead times.

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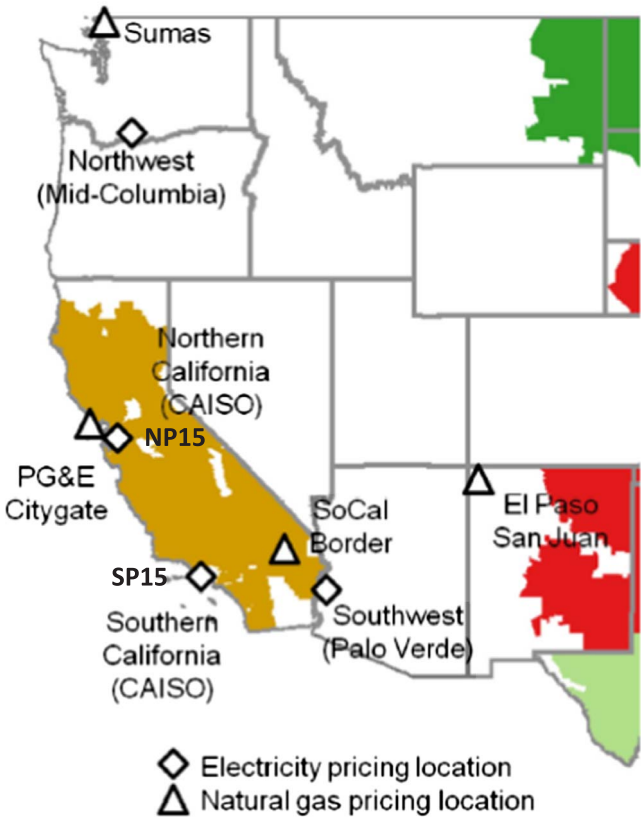

Fig. 1. Major pricing locations in the Western Interconnection (Source: https://www.eia.gov/electricity/monthly/update/wholesale_markets.cfm#tabs_wh_price-3).

thanks to the global potential of solar and wind resources [55–57], as well as government policies such as feed-in-tariff, easy transmission access, renewable portfolio standard (RPS), low-cost financing, and tax subsidies [58–66]. With its zero fuel cost, renewable energy like wind displaces thermal generation via the merit order effect that reduces wholesale market prices [67]. This merit order effect has empirically been observed in Europe (e.g., Denmark, Germany and Spain), North America (e.g., the Northwestern states, California, Texas, and the Northeastern states) and Australia [68–84]. While benefitting electricity consumers, such price reductions worsen thermal generation's investment incentive, necessitating the use of long-term contracts to ensure an electric grid's resource adequacy for safe and reliable service [85–89].

The third event is de-carbonization, underscored by the international commitments made in the 2015 Paris Climate Change Summit and the China-U.S. bilateral agreement ratified in the 2016 G20 Summit in Hangzhou China. Cap-and-trade (C & T) of CO_2 allowances is a market-based mechanism for effective de-carbonization [90–93]. Research concerning carbon trading includes a C & T program's effects on CO_2 emissions reduction, generation profit and investment, supply behavior, electricity market prices, and renewable energy development [94–107]. As part of this research, an important inquiry is the extent of electricity market prices' pass-through of fossil fuel generation's marginal CO_2 emissions cost. Extant regression analyses of market data have not yielded findings that paint a consensus picture of the pass-through extent. Examples of such findings include: (a) an almost 100% pass-through in the Spanish electricity prices [108]; (b) a pass-through of 84–104% in the German electricity prices [109]; (c) a statistically insignificant pass-through for the second phase of the European Union Emission Trading System (EU ETS) [110]; (d) rising CO_2 prices of EU ETS permits having a stronger impact on wholesale electricity prices than falling CO_2 prices [111]; and (e) an approximately 0.32% increase in the European electricity prices due to a 1% increase in the CO_2 price [112].

Motivated by the three transformative events' empirics, this paper applies a regression-based approach to analyze the newly available market data from the California Independent System Operator (CAISO). Besides data availability, California is chosen herein because of the state's salient features of restructured electricity markets, sheer size, fuel diversity, aggressive RPS, and leadership in combatting global warming. This combination of features makes our California-based empirical findings interesting not only to academic researchers and industry practitioners, but also relevant for public policy decision making for a clean and sustainable electricity future.

Generalizing the regression specifications in [45,46,78–84,89], our proposed approach is applicable to other jurisdictions with similar data availability when implementing a C & T program (e.g., Alberta and Ontario in Canada; the Pacific Northwest, Texas, PJM, New England and New York in the U.S.; Denmark, Germany and Spain in Europe; Australia and New Zealand). It can also be used to analyze the market data that will become available in a country like China that continues its electricity market restructuring, has large-scale renewable energy development, and has implemented carbon trading [113–124].

Our paper answers three research questions of substantive policy relevance:

(1) Do the CAISO's day-ahead market (DAM) prices contain a CO_2 premium that has distributional impacts on energy consumers? If the premium is found to mainly exist in the daytime hours, it has bigger bill impacts on electricity consumers with relatively more daytime consumption. The same premium is a subsidy to existing CO_2 emitters that receive the C & T program's allocation of free allowances.
(2) What is the extent of the DAM prices' pass-through of natural-gas-fired generation's marginal cost of CO_2 emissions? In principle, this marginal cost can be calculated as the product of the CO_2 price determined by C & T, CO_2 emissions from burning natural gas, and the marginal generation unit's heat rate. An incomplete pass-through reveals a limited incorporation of CO_2 emissions' cost in producers' bid curves. An excessive pass-through reflects a market price markup beyond the marginal CO_2 cost, signaling generators' exercise of their market power. Either outcome poses a regulatory challenge in the quest for a transparent and competitive electricity market.
(3) Does the extent of pass-through vary by time-of-day (TOD) period? One may conjecture that the DAM price's pass-through should be relatively low for the hours of 00:00–06:00 when the system's dispatched generation units in real time are mostly CO_2-free (e.g., nuclear or wind). While intuitive, this conjecture ignores the CAISO's anticipated need for natural-gas fired generation units with fast ramp rates to stand ready to provide reliability support in those hours.

To answer above questions, we estimate the empirical relationship between the CAISO's location-specific DAM prices by TOD period and their fundamental drivers, which are the day-ahead forecasts of the CO_2 price, the natural gas price, and the state's system demands, solar and wind generation, nuclear capacities available, and hydro conditions. Not attempted for other jurisdictions, this comprehensive estimation is made possible by the CAISO's rich daily market data for the 65-month period of 01/01/2011 to 05/31/2016 that covers 24 pre-C & T months and 41 post-C & T months.

We report two key findings. First, the CAISO's DAM prices contain a CO_2 premium that tracks the day-ahead forecast of the CO_2 price. This finding prevails in the six TOD periods defined in Section 2, supporting the hypothesis of a 100% CO_2 cost pass-through in a competitive wholesale electricity market with price-insensitive demands. Second, the CAISO's DAM prices tend to decline with the day-ahead forecasts of renewable generation and nuclear capacity available but increase with those of the natural gas price and market demands. These estimated