Energy Policy 92 (2016) 299–312

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Merit-order effects of renewable energy and price divergence in California's day-ahead and real-time electricity markets

C.K. Woo [a,*], J. Moore [b], B. Schneiderman [b], T. Ho [c], A. Olson [b], L. Alagappan [b], K. Chawla [b], N. Toyama [d], J. Zarnikau [e]

[a] Department of Asian and Policy Studies, Hong Kong Institute of Education, Hong Kong
[b] Energy and Environmental Economics, Inc. (E3), 101 Montgomery Street, Suite 1600, San Francisco, CA 94104, USA
[c] Independent SAS Analyst, Flat H, 16/F, Block 3, Wing Fai Centre, Fanling, N.T., Hong Kong
[d] Sacramento Municipal Utilities District, 6301 S Street, Sacramento, CA 95817, USA
[e] Frontier Associates LLC, 1515 S. Capital of Texas Highway, Suite 110, Austin, TX 78746, USA

HIGHLIGHTS

- Estimate the day-ahead and real-time merit-order effects of renewable energy in California.
- Document statistically significant merit-order effects of solar and wind energy.
- Document the difference between the day-ahead and real-time prices.
- Attribute the price differences to forecast errors for load, solar and wind energy.
- Discuss the evidence's implications for California's energy policy.

ARTICLE INFO

Article history:
Received 10 August 2015
Received in revised form
7 February 2016
Accepted 12 February 2016

Keywords:
Electricity prices
Day-ahead market
Real-time market
Renewable energy
Merit-order effects
California

ABSTRACT

We answer two policy questions: (1) what are the estimated merit-order effects of renewable energy in the California Independent System Operator's (CAISO's) day-ahead market (DAM) and real-time market (RTM)? and (2) what causes the hourly DAM and RTM prices to systematically diverge? The first question is timely and relevant because if the merit-order effect estimates are small, California's renewable energy development is of limited help in cutting electricity consumers' bills but also has a lesser adverse impact on the state's investment incentive for natural-gas-fired generation. The second question is related to the efficient market hypothesis under which the hourly RTM and DAM prices tend to converge. Using a sample of about 21,000 hourly observations of CAISO market prices and their fundamental drivers during 12/12/2012–04/30/2015, we document statistically significant estimates (p-value ≤ 0.01) for the DAM and RTM merit-order effects. This finding lends support to California's adopted procurement process to provide sufficient investment incentives for natural-gas-fired generation. We document that the RTM-DAM price divergence partly depends on the CASIO's day-ahead forecast errors for system loads and renewable energy. This finding suggests that improving the performance of the CAISO's day-ahead forecasts can enhance trading efficiency in California's DAM and RTM electricity markets.

1. Introduction

This paper is motivated by two transformative events that have already taken place in the electricity industry. The first event is the electricity market reforms that have led to competitive wholesale markets in Europe, North America, South America, Australia, and New Zealand (Sioshansi, 2013). In the U.S., wholesale electricity trading may occur in the centralized day-ahead market (DAM) and real-time market (RTM) operated by an independent system operator (ISO). An important case in fact is the California Independent System Operator (CAISO). Based on the concept of locational marginal pricing (LMP) (Bohn et al., 1984; Hogan, 1992; Stoft, 2002), the CAISO determines DAM and RTM prices daily via least-cost dispatch of generators' supply offers to reliably meet the locational demands.

* Corresponding author.
E-mail addresses: ck@ethree.com (C.K. Woo), jack@ethree.com (J. Moore), brendan@ethree.com (B. Schneiderman), hstony1@hotmail.com (T. Ho), arne@ethree.com (A. Olson), lakshmi@ethree.com (L. Alagappan), kiran@ethree.com (K. Chawla), nate.Toyama@smud.org (N. Toyama), jayz@frontierassoc.com (J. Zarnikau).

http://dx.doi.org/10.1016/j.enpol.2016.02.023
0301-4215/

Wholesale electricity prices are inherently volatile due to: (a) daily fuel-cost variations, especially for natural gas, which is widely used by combustion turbines (CT) and combined-cycle gas turbines (CCGT) in North America; (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 (Li and Flynn, 2006; Bunn and Fezzi, 2007; Woo et al., 1998, 2007, 2011c; Miller et al., 2008; Newcomer et al., 2008; Tishler et al., 2008).[1]

The volatile spot-market prices, even with occasional spikes during hours of severe shortage, may not suffice to justify the CT and CCGT investment necessary for reliable grid operation (Neuhoff and Vries, 2004; Wangensteen et al., 2005; Roques et al., 2005; Newbery, 2010; Milstein and Tishler, 2012; Brattle Group, 2012). This generation investment problem was recently noted by a senior manager of Pacific Gas & Electric (PG&E), the largest utility in Northern California: "Energy revenues based on competitive prices are often not compensatory to cover longer-term cost of building and operating a new plant. For example, in the California market in 2013, the Department of Market Monitoring estimated that energy market revenues for a new combined cycle plant would be $296.39/kW-yr. in comparison to the $256.78/kW-yr. in operating costs and $175.80/kW-yr in annualized fixed costs" (Griffes, 2014, p.27).

To remedy the "missing money" problem of inadequate investment incentive described by Joskow (2013), California adopted an administrative resource adequacy policy in 2004 which obligates the state's investor-owned utilities to bilaterally contract with generators to meet anticipated needs: "Each [load serving entity's] system requirement is 100 percent of its total forecast load plus a 15 percent reserve, for a total of 115 percent."[2] In compliance with its system requirement, a local distribution company (LDC) such as PG&E prepares a long-term procurement plan for the approval of the California Public Utilities Commission (CPUC), announces its capacity needs based on the approved procurement plan, and issues requests for proposals (RFP) from suppliers of conventional and renewable generation, as well as demand response resources.[3]

Under the LDC's RFP process, a developer of a new CCGT (or CT) may submit its proposal for a long-term contract, which presumably contains sufficient revenues to cover the annualized fixed and variable costs of the new plant. The winning proposal of a chosen developer should contain sufficient revenues to enable the new plant's construction, thus solving the "missing money" problem.

To address the "missing money" problems outside California, capacity markets were introduced in the late 1990 s in the U.S. deregulated markets of New York, PJM, and New England (Spees et al., 2013). The notable exception is the Electric Reliability Council of Texas (ERCOT), which continues to use an energy-only market design with a high offer cap ($9,000/MWh beginning June 1, 2015) to provide generation investment incentives.

The second event motivating this paper is the development of solar and wind energy in many parts of the world due to resource abundance (Hoogwijk et al., 2004; Lu et al., 2009; Marini et al., 2014) and government policies that include easy and low-cost transmission access, financial incentives (e.g., feed-in-tariffs, government loans and grants, and tax credits), and quota programs (e.g., renewables portfolio standards, or RPS, cap-and-trade programs for carbon emissions certificates, and renewable-energy credits).[4]

Wind energy displaces thermal generation with relatively high fuel costs and reduces wholesale market prices (European Wind Energy Association, 2010). This price-reduction effect, also known as the merit-order effect, has been demonstrated through model simulations (e.g., Morales and Conejo, 2011; Traber and Kemfert, 2011), as well as through regression analysis of market data for Spain (Gelabert et al., 2011; Gil et al., 2012), Germany (Sensfuß et al., 2008; Ketterer, 2014; Paraschiv, et al., 2014), Denmark (Munksgaard and Morthorst, 2008; Jacobsen and Zvingilaite, 2010), Australia (Cutler et al., 2011), Texas (Woo et al., 2011b; Zarnikau et al., 2014), PJM (Gil and Lin, 2013), the Pacific Northwest (Woo et al., 2013), and California (Woo et al., 2014, 2015a).

While potentially benefiting electricity consumers by reducing electricity prices and monthly bills (Gil and Lin, 2013; Woo et al., 2013, 2014),[5] the merit-order effect also weakens the investment incentive for the CT and CCGT, as documented by the simulation study of Traber and Kemfert (2011) for Germany, the regression analyses of Woo et al. (2012, 2015a) for Texas and California, and the descriptive assessment of Steggals et al. (2011) for Great Britain.

Applying a regression-based approach to a recent sample about 21,000 hourly observations of CAISO market prices and their fundamental drivers for 12/12/2012–04/30/2015, this paper answers two policy questions that are of interest to academics and policy makers. The first question is what are the estimated merit-order effects of renewable energy in the CAISO's DAM and RTM? This timely and relevant question reflects the CAISO's DAM trading, which accounts for over 90% of the total MWh transacted in 2014. If the DAM merit-order effect estimate is found to be small, California's renewable energy development is of limited help in mitigating the adverse bill impacts of such events as escalating natural gas prices, rapid load growths or nuclear plant shutdowns. To be fair, a small DAM merit-order effect may also imply a small "missing money" problem.

The second question is what causes the hourly DAM and RTM prices to systematically diverge? Under the efficient market hypothesis (Eydeland and Wolyniec, 2003), the CAISO's DAM and RTM prices tend to converge. If an expected DAM price is less than an expected RTM price, buying electricity in the DAM for resale in the RTM yields a per MWh arbitrage profit equal to the expected

[1] Price volatility with occasional spikes has led to extensive research on electricity price behavior and dynamics (e.g., Johnsen, 2001; Bessembinder and Lemmon, 2002, 2006; Longstaff and Wang, 2004; Knittel and Roberts, 2005; Park et al., 2006; Haldrup and Nielsen, 2006; Mount et al., 2006; Weron, 2006; Guthrie and Videbeck, 2007; Benth and Koekebakker, 2008; Karakatsani and Bunn, 2008; Redl et al., 2009; Marckhoff and Wimschulte, 2009; Janczura and Weron, 2010; Douglas and Popova, 2011). That volatility has also engendered extensive research on electricity derivatives and risk management (e.g., Deng et al., 2001; Lucia and Schwartz, 2002; Eydeland and Wolyniec, 2003; Burger et al., 2004; Kleindorfer and Li, 2005; Deng and Oren, 2006; Deng and Xia, 2006; Woo et al., 2004a, 2004b, 2006; Huisman et al., 2009; Camona and Ludkovski, 2008; Ryabchenko and Uryasev, 2011; Thompson, 2013).

[2] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/.

[3] CPUC, "2014 Final RA Guide", http://www.cpuc.ca.gov/NR/rdonlyres/0C2512A4-AE6C – 4BB7-BC0D – 75D2F40741BA/0/Final2014RAGuide.docx.

[4] These policies are detailed in Haas et al. (2008), Schmalensee (2009), Barroso et al. (2010), Pollitt (2010), Alagappan et al. (2011), Woo et al. (2011a), Zarnikau (2011), Yatchew and Baziliauskas (2011), and Green and Yatchew (2012).

[5] In California, renewable energy's per-MWh procurement cost includes the renewable energy cost and incremental transmission and grid integration costs. These procurement costs are typically higher than wholesale market prices and must be paid by the customers of a load serving entity such as an LDC. As renewable energy can also reduce wholesale market prices, the net bill effect to customers is the difference between (a) the incremental above-market procurement cost of renewable energy; and (b) the cost savings due to lower market prices for the MWh supplied by non-renewable generation. The LDC's customers enjoy net bill savings when (a) is less than (b).