The Electricity Journal 29 (2016) 18–22

Contents lists available at ScienceDirect

The Electricity Journal

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

What happens in California does not always stay in California: The effect of California's cap-and-trade program on wholesale electricity prices in the Western Interconnection

A. Olson[a,*], C.K. Woo[b], N. Schlag[a], A. Ong[a]

[a] Energy and Environmental Economics, Inc. (E3), 101 Montgomery Street, Suite 1600, San Francisco, CA 94104, USA
[b] Department of Asian and Policy Studies, Hong Kong Institute of Education, Hong Kong

ARTICLE INFO

Article history:
Available online 30 August 2016

Keywords:
Cap-and-trade program
CO_2 price
Wholesale electricity prices
California
Western Interconnection

ABSTRACT

An examination of the effect of California's cap-and-trade program on wholesale electricity prices in the Western Interconnection finds that the CO_2 price is fully captured by California electricity prices, but also by prices at the Mid-Columbia hub in the Pacific Northwest. This occurs because, under California rules, Northwest generators can export carbon-free hydroelectricity to California at premium prices.

1. Introduction

The Western Interconnection is a synchronous electric grid that covers parts of 14 western states, two Canadian provinces, and one Mexican state. Within the Western Interconnection, electricity trading takes place largely on a voluntary, bilateral basis among the 39 Balancing Authorities and other market participants. Bilateral prices are reported to index publishers such as Platts or SNL at pricing hubs including North of Path 15 (NP15) and South of Path 15 (SP15) in California, Mid-Columbia (Mid-C) in the Pacific Northwest, and Palo Verde (PV) in the Desert Southwest (Woo et al., 1997). Absent transmission congestion, the law of one price under inter-regional trading implies convergence of the NP15, SP15, Mid-C and PV prices, reflecting that the Western grid operates as an integrated aggregate market.

Jan. 1, 2013, marked the beginning of California's cap-and-trade (C&T) program for CO_2 allowances.[1] The program is one component of the California Air Resources Board's (ARB) regulations implementing the requirements of Assembly Bill 32, California's Global Warming Solutions Act, to reduce statewide greenhouse gas (GHG) emissions to 1990 levels by 2020.[2] Under C&T, California generators must surrender an emissions allowance for each ton of GHG emissions. The purpose of California's C&T program is to enhance the profitability of clean energy sources, while internalizing the formerly unpriced externality of CO_2. This article investigates the extent to which California's program is successful at achieving those goals.

Because California transacts within the context of a broader regional electricity market, a corollary question is what effect, if any, California's C&T program is having on the price of electricity transactions outside of California. A large portion of Northwest hydroelectric assets qualify as carbon-free power based on California regulations. California's C&T program may therefore be having an impact on electricity market prices at the Mid-C trading hub.

Using a recent 65-month (01/01/2011 through 05/31/2016) sample of daily observations, this article offers a first look at the California CO_2 price's effects on the day-ahead wholesale market prices at four markets of the Western Interconnection: the North of Path 15 (NP15) and South of Path 15 (SP15) in California, the Mid-Columbia (Mid-C) in the Pacific Northwest, and the Palo Verde (PV) in the Desert Southwest. We find that what happens in California does not always stay in California.

The NP15, SP15 and Mid-C prices are found to fully capture the CO_2 price. The PV price, however, is not estimated to have a premium that reflects the CO_2 price. These findings reflect the fact that Pacific Northwest hydroelectric generators may export carbon-free hydroelectricity as specified sources to California at a price tied to NP15, whereas the electricity traded in the Desert Southwest is sold at a discount to the SP15 price due to the CO_2

* Corresponding author.
E-mail address: arne@ethree.com (A. Olson).

[1] A description of the California C&T program is available at http://www.arb.ca.gov/cc/capandtrade/guidance/cap_trade_overview.pdf.

[2] http://www.arb.ca.gov/cc/ab32/ab32.htm.

http://dx.doi.org/10.1016/j.tej.2016.08.003
1040-6190/

content of the PV transactions. Thus, the effects of C&T on the Western Interconnection's wholesale market prices are an outcome of inter-regional trading among the regions with different generation resource mixes.

2. The effect of California's CO_2 price on wholesale electricity market prices

California has an installed capacity of 79,359 MW,[3] with a generation mix dominated by natural-gas-fired generation (Woo et al., 2014, 2016). Due to its relatively high cost, the state's marginal generation fuel is typically natural gas during the heavy-load-hour (HLH) period commonly used in the Western Interconnection's day-ahead bilateral electricity trading: 06:00–22:00, Monday through Saturday, excluding holidays (Woo et al., 2013, 2015).

Suppose the marginal generation unit during peak hours is a combustion turbine with a heat rate of ~9 MMBTU per MWh. Under 100% pass-through, the marginal effect of the CO_2 price on the electricity price is product of (a) the $1 increase in the CO_2 price ($/metric ton); (b) the CO_2 content of burning natural gas (=0.053 metric ton/MMBTU)[4]; and (c) the marginal heat rate of a combustion turbine (CT) (=~9 MMBtu/MWh). Hence, the resulting California electricity price increase during peak hours should be around $0.48/MWh (=$0.053 \times 9$), a useful benchmark for measuring an electricity price's CO_2 premium.

California's C&T program may also have an impact on wholesale electricity prices at other western trading hubs. Per the ARB rules, electricity imports can come from either "specified" sources, where the source of the generation is identified and subject to unit-specific GHG emissions factors, or "unspecified" sources, which are assigned a default emissions rate of 0.428 metric tons per MWh. Specified generation sources include all out-of-state generation (principally renewable and coal-fired generators) owned by or contracted to California load-serving entities (LSEs), as well as many hydroelectric generators in the Pacific Northwest selling surplus hydropower to California.[5]

In addition, a special status is afforded to the Bonneville Power Administration (BPA) in the Pacific Northwest states and the British Columbia Hydro and Power Authority (BC Hydro) in western Canada that trades in the U.S. through its marketing subsidiary Powerex. Both BPA and BC Hydro operate very large hydroelectric systems but are prevented by statute from selling unit-specific power outside of their jurisdictional service areas. In recognition of their unique status, the ARB developed the "Asset-Controlling Suppliers" (ACS) designation, assigning BPA and Powerex deemed GHG emissions rates that reflect their hydro-dominant portfolios.[6]

All imports without a specified generation source are deemed "unspecified" sources and are assigned a default emissions rate of 0.428 MMT/MWh. This default emissions rate corresponds to a relatively efficient gas-fired generator with a heat rate of approximately 8.1 MMBtu/MWh.

Because Pacific Northwest hydroelectric generators can sell specified hydropower to California at a price premium relative to unspecified power, the Mid-C price may be affected by the California CO_2 price. Our previous work estimated this effect using the GridView production simulation model that offers an *ex ante* assessment based on forward-looking assumptions of the Western Interconnection's generation mix and fuel costs, transmission capabilities, and demand conditions. "Hurdle rates" are applied at California Balancing Area boundaries reflecting the ARB's default emissions rate multiplied by the applicable CO_2 price.

Fig. 1 shows the transmission topology utilized by the Western Electric Coordinating Council's (WECC) Transmission Expansion Planning and Policy Committee (TEPPC) to simulate this effect in GridView for its widely referenced planning studies. Hurdle rates are imposed to restrict otherwise profitable trade between two regions. The hurdle rates can be tiered, with $0.53/MWh applicable to the Tier 1 Imports based on the BPA's ACS deemed carbon emissions rate. The quantity of potential Tier 1 Imports (the Tier 2 threshold) varies monthly based on estimates of surplus hydropower available from BPA. A hurdle rate of $11.97/MWh is applied to all imports above the Tier 2 threshold, based on the ARB default carbon emissions rate for unspecified sources.

The $11.97/MWh hurdle rate is applied to all other imports to California. Because the PV hub is not in a hydro-rich area, nearly all imports from the PV area will be from gas or coal generators, requiring the buyer to submit a CO_2 allowance under the C&T program once the power is imported into California. California's CO_2 price is therefore expected to have a lower impact on the PV wholesale price, since a California buyer must also purchase a CO_2 allowance.

The GridView results suggest the following effects on market prices:

- At the SP15 hub, a $1/metric ton increase in the CO_2 price results in a $0.372/MWh increase in the wholesale electricity market price during all hours of the year. This implies an average marginal heat rate of 7 MMBTU/MWh, similar to the heat rate of a combined-cycle combustion turbine.
- At the Mid-C hub, a $1/metric ton increase in the CO_2 price results in a $0.086/MWh increase in the wholesale electricity market price during all hours of the year. This suggests that the California C&T program will affect Mid-C prices, but only at a fraction of the rate that it affects California prices (the Mid-C price increase is only 23% of the SP15 price increase).
- At the PV hub, a $1/metric ton increase in the CO_2 price results in a $0.003/MWh increase, implying that the California CO_2 price would be expected to have almost no effect on the PV price.

While the GridView simulation produces useful information on the CO_2 price's effects on the Western Interconnection's wholesale electricity prices, we do not know if these *ex ante* estimates are matched by those based on actual market data collected after the California C&T program's commencement on 01/01/2013. Hence, we employ an *ex post* analysis to statistically identify and quantify the CO_2 price's effects using actual market price data.

3. Data description

We obtain the day-ahead prices for the four markets from SNL Financial LC (www.snl.com) for the recent period of 01/01/2011–05/31/2016. This period includes the 24 months before and the 41 months after the start of California's C&T program on 01/01/2013, thus enabling a statistical detection of the CO_2 price's effects on the four wholesale electricity prices.

We focus on the HLH price series because (a) the SNL data files do not have weekend prices; (b) almost half of the PV prices file has missing data for the daily light-load-hour (LLH) prices for hours outside the HLH period; and (c) there are no LLH prices for NP15 and SP15.

Table 1 presents the descriptive statistics of the data used in our regression analysis. Each price regression's left-hand-side variable

[3] http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html.

[4] The U.S. EIA reports that the CO2 content of burning natural gas is 117 pounds/MMBTU = 53 kg/MMBTU (https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11).

[5] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/specified_source_acs_faqs.pdf.

[6] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm.