Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Director, Department of Market Monitoring

Date: September 5, 2013

Re: **Market Monitoring Report**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides an update on market performance in 2013 by the Department of Market Monitoring (DMM). Electricity market prices in the first eight months of 2013 have been about 60 percent higher than during the same period in 2012. The main reasons for this price increase include the following:

- Gas prices have risen about 42 percent since the unusually low gas prices that occurred in 2012. This accounts for most of the increase in prices since last year.
- The rest of the increase in electricity market prices since last year can be primarily attributed to implementation of the state's greenhouse gas cap-and-trade program. DMM estimates day-ahead market prices in the second quarter were about $6/MWh higher with implementation of this program. This is highly consistent with the cost of carbon emission credits and the efficiency of gas units typically setting prices in the day-ahead market.
- Other factors causing upward pressure on electricity market prices include a decrease in hydro-electric generation (around 25 percent in the second quarter) and a small increase in load (about 1.5 percent at peak).
- Factors leading to higher prices were partially offset by significant increases in energy from wind and solar resources directly connected to the ISO grid, which have provided about 8.3 percent of system energy in 2013 compared to about 5.6 percent in the same months of 2012. This does not include renewable energy from imports, distributed solar generation and other forms of renewable energy which are also growing rapidly.

The remainder of this memo provides a more detailed summary of energy market performance, as well as DMM's analysis of the impact of the state's greenhouse gas cap-and-trade program on the ISO's day-ahead energy market.

Energy market performance

This section provides a more detailed summary of energy market performance from January through August 2013.

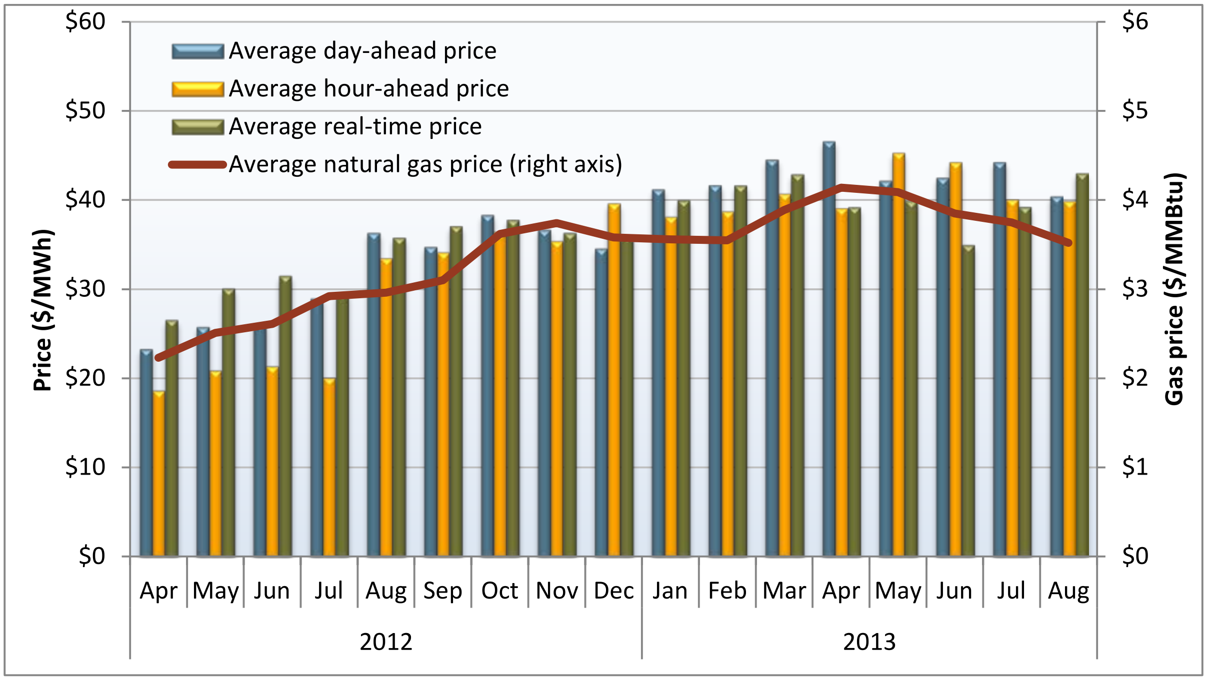
Price levels remain significantly higher in 2013 compared to 2012. Average system energy prices in the ISO market continued to stay higher in the first eight months compared to price levels in 2012 (see Figure 1). This increase is primarily the result of a 42 percent increase in regional natural gas prices. Most of the remainder of the increase in prices can be attributed to compliance costs associated with the state's cap-and-trade program, which DMM estimates has also added about $6/MWh to day-ahead market prices. Other factors causing upward pressure on electricity market prices include a decrease in hydro-electric generation (around 25 percent in the second quarter) and a small increase in load (about 1.5 percent at peak).

Wind and solar energy continue to increase significantly. Factors leading to higher prices in 2013 have been partially offset by significant increases in wind and solar energy. In 2013, energy from wind and solar resources directly connected to the ISO grid have provided about 8.3 percent of system energy in 2013 compared to about 5.6 percent in the same months of 2012. This does not include renewable energy from imports, distributed solar generation and other forms of renewable energy which are also growing rapidly. The increase in solar energy has been even greater during the peak summer months. During the hour of peak daily demand in July (hour 16), solar resources directly connected to the ISO grid provided about 1,700 MW, compared to about 900 MW during July 2012.

Lower real-time prices have created divergence between average day-ahead and real-time system energy prices. Average system energy prices in the real-time market (excluding congestion) have tended to be systematically lower than average prices in the day-ahead market (see Figure 1). This trend began to change in August, as higher prices on a few days related to outages have driven real-time prices substantially higher. The lower real-time prices during much of year has been due in part to substantial amounts of wind and solar energy in the real-time market that was not scheduled in the day-ahead. Energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches due to pre-summer testing also contributed to lower real-time prices. Finally, the incidence of real-time price spikes has decreased, which has further lowered average real-time prices.

Increased divergence between day-ahead and hour-ahead system energy prices. Average system energy prices in the hour-ahead market were higher than day-ahead prices in May and June, as seen in Figure 1. These differences in average prices were driven by extremely high hour-ahead prices during a relatively small number of hours. Hour-ahead prices fell below day-ahead prices in July and August as these months did not have extreme hour-ahead prices.

Figure 1. Average monthly system marginal energy prices (all hours)



Greenhouse Gas Cap-and-trade program

Summary

Generating resources became subject to California's greenhouse gas cap-and-trade program compliance requirements starting on January 1, 2013. This section highlights the impact of these requirements in the first and second quarters. These highlights include the following:

- The cost of greenhouse gas emissions permits has been relatively stable, averaging \$14.55/mtCO_2e for the first quarter and \$14.59/MtCO_2e for the second quarter.[1]
- Based on statistical analysis of changes in day-ahead market energy prices following the cap-and-trade implementation, DMM estimates that average wholesale prices are about \$6/MWh in the first half of 2013 due to cap-and-trade compliance costs. This is very consistent with the emissions costs for gas units typically setting prices in the ISO market.
- Imports do not appear to have decreased in response to implementation of the cap-and-trade program. In fact, import schedules and bid-in volumes increased in the first half of 2013 compared to the first half of 2012.

[1] mtCO_2e stands for metric tons of carbon dioxide equivalent, a standard emissions measurement.

The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the CPUC and other state entities. Under the cap-and-trade program, allowances were allocated to the state's electric distribution utilities to help reduce the costs incurred by electricity customers due to the program. The investor-owned electric utilities are required to sell all of their allowances in quarterly auctions held by the California Air Resources Board (CARB). Proceeds from the auction are to be used for the benefit of retail ratepayers, consistent with the goals of AB 32. Under a 2012 CPUC decision, revenue from carbon emission allowances sold at auction will be used to reduce offset impacts on retail costs.[2]

Background

California's cap-and-trade program covers major sources of greenhouse gas emissions including power plants. Sources under the cap are required to submit allowances and offsets equal to their emissions at the end of each compliance period. The program includes an enforceable emissions cap that will decline over time. The cap on total emissions is set to decline 2 percent annually until 2014 and then about 3 percent annually through 2020.

Allowances are available at quarterly auctions held by the Air Resources Board and may also be traded bilaterally. In addition, financial derivatives based on allowance prices are traded on public exchanges such as the InterContinental Exchange (ICE).

Allowances are associated with a specific year, which is known as the *vintage*. Allowances are *bankable*, meaning that an allowance may be submitted for compliance in years subsequent to the vintage of the allowance. *Borrowing* of allowances is not allowed, meaning that permits for future years cannot satisfy compliance requirements in an earlier year.

The cap-and-trade program affects wholesale electricity market prices in two ways. First, market participants covered by the program will presumably increase bids to account for the incremental cost of greenhouse gas allowances. Second, the ISO amended its tariff, effective January 1, 2013, to include greenhouse gas compliance cost in the calculation of each of the following:

- Resource commitment costs (start-up and minimum load costs);
- Default energy bids, which are bids used in the automated local market power mitigation process; and
- Generated bids (bids generated on behalf of resource adequacy resources and as otherwise specified in the ISO tariff).

The ISO uses a calculated greenhouse gas allowance index price as a daily measure of the cost of greenhouse gas allowances. The ISO greenhouse gas allowance price is calculated

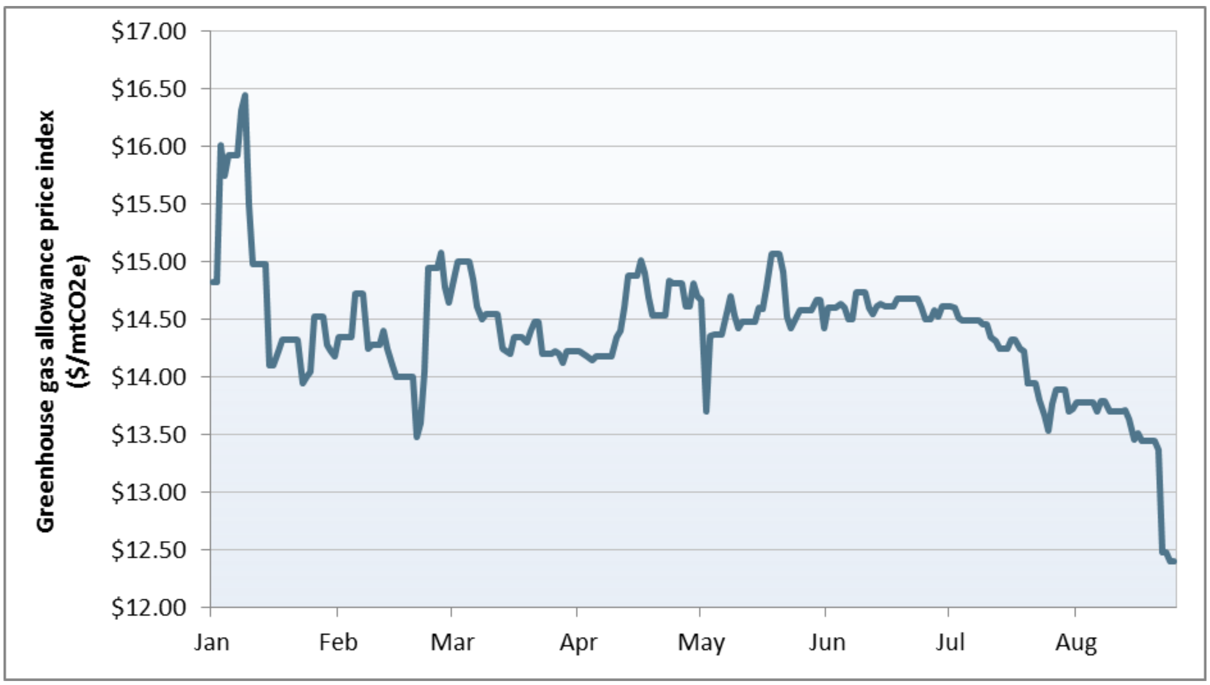
[2] Pursuant to CPUC decision Docket No. R.11-03-012, the investor-owned utilities will distribute this revenue to emissions-intensive and trade-exposed businesses; to small businesses; and to residential ratepayers to mitigate carbon costs. Remaining revenues will be given to residential customers as an equal semi-annual bill credit. See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M039/K594/39594673.PDF.

as the average of two market based indices.[3] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 2.

After rising to over \$16/mtCO_2e in the first week of 2013, the ISO greenhouse gas allowance index prices dropped and were fairly constant, varying between \$13.50/mtCO_2e and \$15/mtCO_2e. The average value of the index was \$14.59/mtCO_2e in the second quarter, slightly above the average value for the first quarter: \$14.55/mtCO_2e.

The California Air Resources Board held their fourth auction of greenhouse gas allowances on August 16, 2013.[4] Results were posted on August 21, 2013 with a clearing price of \$12.22/mtCO_2e for 2013 allowances. The decline in the ISO's August greenhouse gas allowance price index is likely related to the auction results.

Figure 2. ISO's greenhouse gas allowance price index



Impact on market prices

DMM has developed a statistical approach to estimate the impact of greenhouse gas costs on day-ahead market prices in the ISO during the eight months of greenhouse gas compliance. This approach relies on the comparison of market data before cap-and-trade implementation with data from the first half of 2013. DMM used a similar model in the first quarter, but improved upon it to control for exogenous differences in generation availability (such as wind) and other factors.

[3] ICE and ARGUS Air Daily.

[4] *See California Air Resources Board Quarterly Auction 4, August 2013*: http://www.arb.ca.gov/cc/capandtrade/auction/august-2013/results.pdf.

The statistical analysis is focused on the day-ahead system marginal energy cost, which excludes the component of the locational marginal prices attributable to transmission congestion. This limits the effects of transmission congestion allowing for the effects of the greenhouse gas costs to be better isolated from congestion.

DMM estimates the impact of greenhouse gas compliance on wholesale energy prices using a multiple linear regression model that assesses average daily system energy prices as a linear function of a measure of the following factors:

- greenhouse gas compliance cost
- gas price indices
- indicator variables for holidays, Saturday, and Sunday
- a non-linear function of expected load
- scheduled generation availability for fuel types that we assume to be exogenous (hydro, wind, solar, geo-thermal, and nuclear), and
- imports (as modeled by exogenous gas price indices).

Using this model, DMM estimates that in the first eight months of 2013 the impact of greenhouse gas compliance was about $6.04/MWh. The model predicts the average ISO day-ahead system energy prices fairly well, explaining approximately 92 percent of the variation in this measure in both models. This analysis may be refined as further data becomes available.

Results of this statistical analysis are highly consistent with expectations of the impact of greenhouse gas compliance costs on wholesale electricity costs during a period when market prices are being set close to the marginal operating cost of relatively efficient units. For example, given an average emission cost of \$14.59/mtCO_2e, an additional cost of $6.21/MWh represents the emission cost of a gas-fired unit with a heat rate of 8,000 Btu/kWh.[5]

Implied heat rates

A simpler method that is commonly used to assess changes in electricity market prices over time is known as the *market heat rate* or *implied heat rate*. The implied heat rate is a standard measure of the maximum heat rate that would be profitable to operate given electricity prices and fuel costs, ignoring all non-fuel costs. The implied heat rate is calculated by dividing the electricity price by fuel price. For instance, if the average price of electricity is $25/MWh and the price of gas is $2.50/mmBtu, this equates to an implied heat rate of 10 mmBtu/MWh.

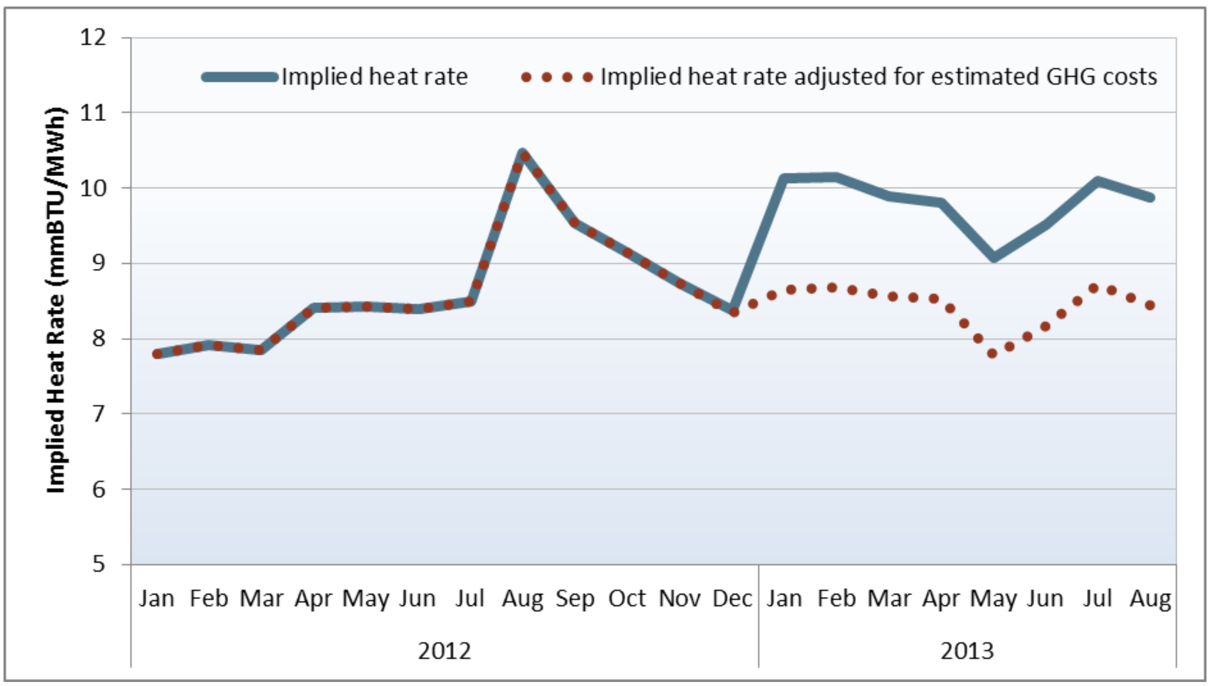
Because the implied heat rate controls for the price of gas, this is often used to assess the degree to which electricity prices have actually changed due to factors other than gas. With the introduction of the cap-and-trade program, this measure must be adjusted to account for the additional cost of greenhouse gas emissions allowances.

[5] \$14.59/mtCO_2e x 0.053165 mtCO_2/MMBtu x 8,000 Btu/kWh = \$6.21/MWh

DMM calculates the implied heat rate adjusted for greenhouse gas compliance costs by first subtracting our estimate of the greenhouse gas compliance cost price impact derived above from the electricity price ($6/MWh). This adjusted electricity price is then divided by the gas price to calculate an implied heat rate that is comparable to this calculation prior to implementation of the cap-and-trade program starting in 2013.

Figure 3 shows the implied heat rate for the day-ahead energy market since January 2012 with and without this adjustment for the increase in price due to the cap-and-trade program. As shown in Figure 3, the implied heat rate before any adjustment for the price impact of the cap and trade program rose significantly starting in January 2013. However, after adjusting for a $6/MWh increase due to the cap-and-trade program, the implied heat rate during the first eight months of 2013 (8.5 mmBtu/MWh) is approximately equal to the implied heat rate during the same months of 2012 (8.4 mmBtu/MWh).

Figure 3. Implied heat rates with and without greenhouse gas compliance costs



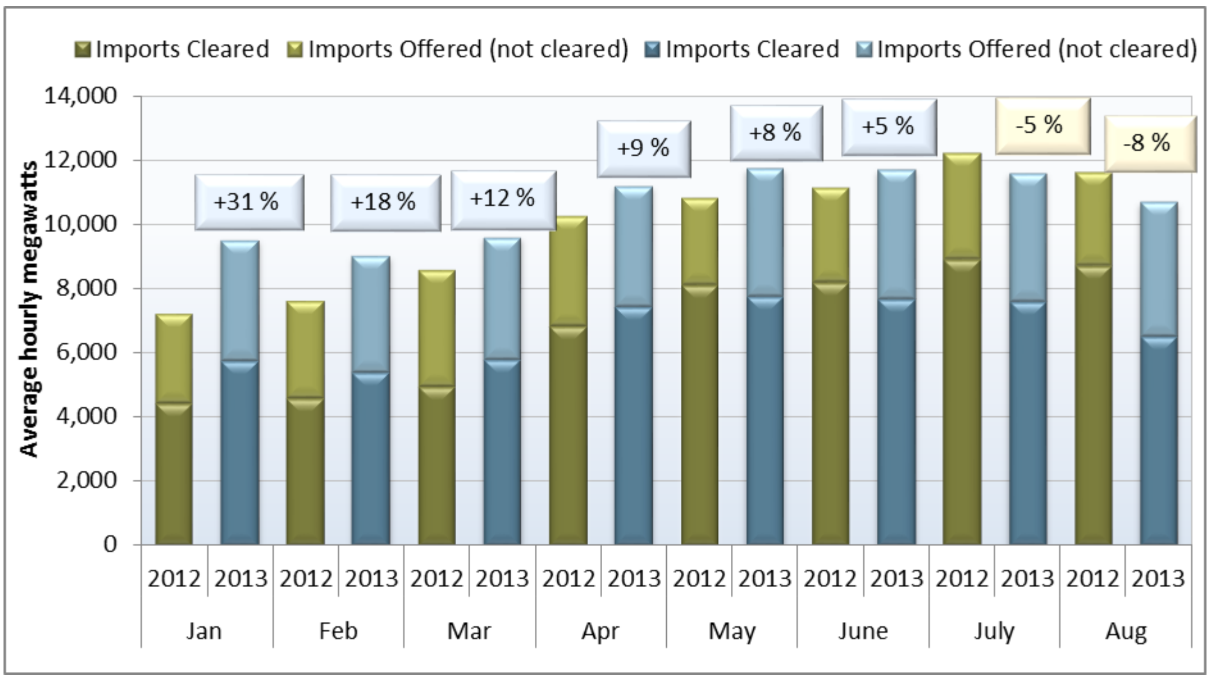
This analysis shows that the increase in day-ahead prices in 2013 can be attributed primarily to the 42-percent increase in the price of gas, along with the $6/MWh increase due to the cap-and-trade program.

Effects of cap and trade program on imports

Nearly 30 percent of ISO load was served by imports from outside the ISO system in 2012, with most of these imports coming from outside California. Prior to the implementation of the cap-and-trade program, stakeholders and regulators were concerned that certain rules related *resource shuffling* would result in reduced imports into California as some participants would elect to no longer import. Ultimately, while the mix of participants that import power into California has changed slightly in 2013, the levels of imports have increased in the first half of 2013, compared to the first half of 2012. While import levels increased in the first half of the year, import levels have declined slightly in July and August of 2013 compared to 2012. This change could be the result of supply conditions outside of California and demand conditions in California in the third quarter.

Figure 4 shows the amount of megawatts bid in at inter-ties and cleared in the day-ahead market in the first 8 months of 2012 and 2013.

Figure 4. Inter-tie imports offered and cleared in the day-ahead market



Percentages in the boxes in Figure 4 highlight the percentage change in total volume of import bids offered each month in 2013 compared to the same month in 2012. In the first half, the total amount of import megawatts offered to the market increased for each month in 2013 compared to the first half of 2012. Overall, import megawatts offered increased by 13 percent in the first half of 2013 compared to the first half of 2012. So far in the third quarter, import megawatts offered are down 6 percent.

As shown by the darker bars in Figure 4, the volume of import bids that cleared the market also increased each of the first four months of 2013 compared to 2012. In May and June the volume of import bids clearing the market dropped slightly compared to 2012. Overall, imports clearing in the market during the first six months of 2013 increased by 7 percent compared to 2012. Imports clearing in the market in July and August are down 20 percent.

However, DMM does not attribute the drop in imports during these more recent months to the cap-and-trade program.

Bid prices for imports have increased notably in the first eight months of 2013 compared to 2012. DMM attributes most of this increase to the 42 percent increase in gas prices over this period. Given the significant change in gas prices over this period, DMM has not sought to quantify the portion of higher import bid prices that may be attributable to greenhouse gas allowance costs.