Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Executive Director, Market Monitoring

Date: March 20, 2019

Re: **Department of Market Monitoring update**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides major findings of the Department of Market Monitoring's forthcoming 2018 annual report, along with an update on key market trends so far in 2019.

Overall market performance in 2018

Total wholesale electric costs increased by about 23 percent, driven primarily by a 25 percent increase in natural gas prices in 2018. After adjusting for higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by about 3 percent from 2017. The total estimated wholesale cost of serving ISO load in 2018 was about $10.8 billion or about $50/MWh, an increase from about $40.3/MWh in 2017.[1]

Figure 1 shows total estimated wholesale costs per megawatt-hour of system load from 2012 to 2016. Wholesale costs are provided in nominal terms (blue bar), and normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The green line represents the annual average daily natural gas price including greenhouse gas compliance.

Table 1 provides annual summaries of nominal total wholesale costs by category from 2014 through 2018. These costs include ancillary services, residual unit commitment, bid cost recovery, and reliability costs for capacity procured under reliability must run contracts and the capacity procurement mechanism. As seen in Table 1, the increase in total cost in 2018 was primarily due to increases in day-ahead energy costs, which increased from $37.18/MWh to $45.16/MWh, or roughly 21 percent from 2017.

[1] Values reported here represent estimated costs to ISO load only. Values reported in DMM's *2017 Annual Report on Market Issues and Performance* include costs to additional balancing areas participating in the energy imbalance market. Cost for areas in the energy imbalance market will be reported separately in DMM's 2018 annual report.

Figure 1. Total annual wholesale costs per MWh of load (2014-2018)

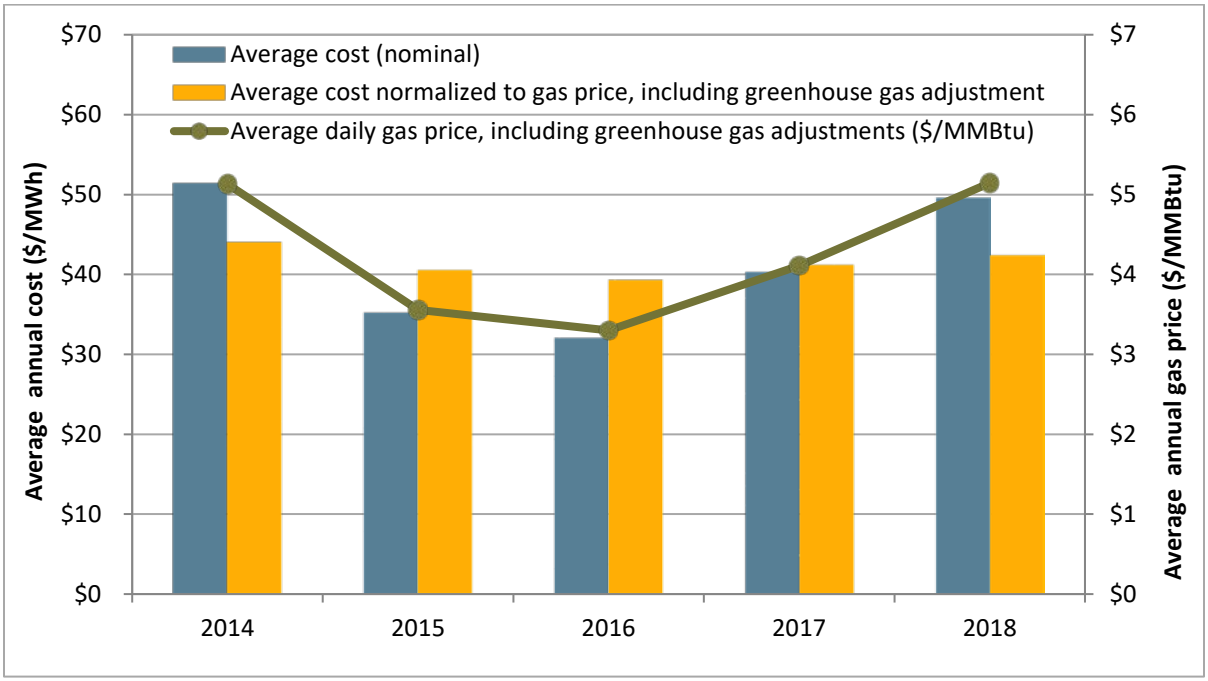

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Table 1. Average wholesale energy costs per MWh (2014-2018)

	2014	2015	2016	2017	2018	Change '17-'18
Day-ahead energy costs	$ 48.14	$ 33.53	$ 30.07	$ 37.18	$ 45.16	$ 7.99
Real-time energy costs (incl. flex ramp)	$ 1.93	$ 0.55	$ 0.71	$ 1.44	$ 1.69	$ 0.25
Grid management charge	$ 0.42	$ 0.42	$ 0.42	$ 0.43	$ 0.43	$ 0.01
Bid cost recovery costs	$ 0.40	$ 0.38	$ 0.30	$ 0.42	$ 0.68	$ 0.26
Reliability costs (RMR and CPM)	$ 0.14	$ 0.12	$ 0.11	$ 0.10	$ 0.70	$ 0.60
Average total energy costs	**$ 51.03**	**$ 35.00**	**$ 31.61**	**$ 39.57**	**$ 48.67**	**$ 9.10**
Reserve costs (AS and RUC)	$ 0.30	$ 0.27	$ 0.54	$ 0.77	$ 0.86	$ 0.08
Average total costs of energy and reserve	**$ 51.33**	**$ 35.27**	**$ 32.15**	**$ 40.34**	**$ 49.53**	**$ 9.19**

In addition to increased natural gas cost increases, a variety of other factors contributed to increased wholesale costs. These include:

- **Reliability costs.** Costs for capacity procured under reliability must-run contracts and the capacity procurement mechanism increased from $24 to $156 million or $0.10/MWh to $0.70/MWh. In 2018, about $56 million of these costs are reliability must-run payments and about $99 million are costs due to capacity procurement mechanism designations. About $78 million of these costs were paid to four resources procured on an annual basis under the capacity procurement mechanism at prices close to or at the soft offer cap.
- **Bid cost recovery.** Bid cost recovery payments increased significantly due to a combination of increased gas costs and actions taken by grid operators due to system conditions in the summers months. In the ISO, these costs increased from $96 to $153 million, or $0.42/MWh to $0.68/MWh. As shown in Figure 2, bid cost recovery payments for the third quarter alone totaled $85 million, the highest amount in any quarter since 2011.
- **Offset costs.** Real-time imbalance offset charges increased from $82 to $127 million, or $0.36/MWh to $0.57/MWh. Real-time congestion imbalances of $117 million account for the majority of these costs in 2018. These charges were driven in large part by reductions in 15-minute market transmission constraint limits below limits used in the day-ahead market.

Wholesale energy cost increases were driven primarily by a 25 percent increase in natural gas prices in 2018. Figure 3 shows monthly average natural gas prices at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate) as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

Gas prices at SoCal Citygate were extremely high on some days in July and August of 2018 due to high natural gas demand and high temperatures, combined with unplanned pipeline maintenance, restricted storage activity at Aliso Canyon and anticipation of potential low operational flow order (OFO) non-compliance penalty charges. Gas prices have remained high since due to ongoing pipeline outages and low OFO penalties.

Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. The sustained increase in natural gas prices, particularly at SoCal Citygate, was one of the main drivers of high system marginal energy prices across the ISO footprint.

Figure 2. Total ISO bid cost recovery costs (2017-2018)

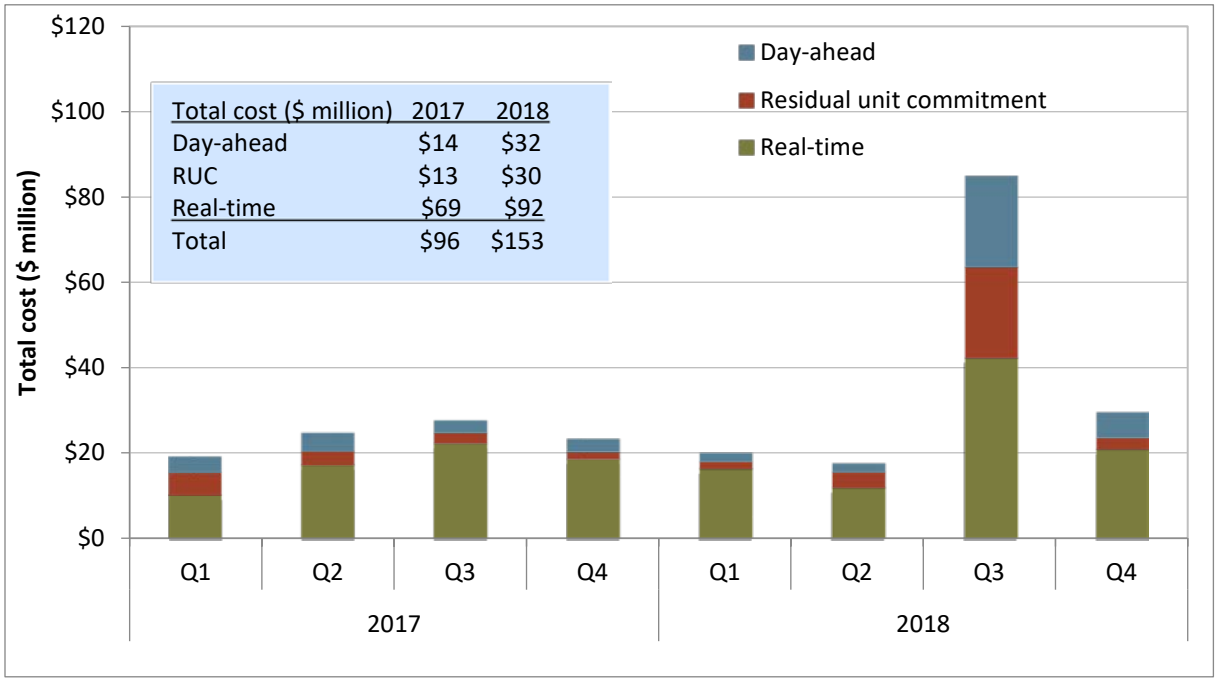
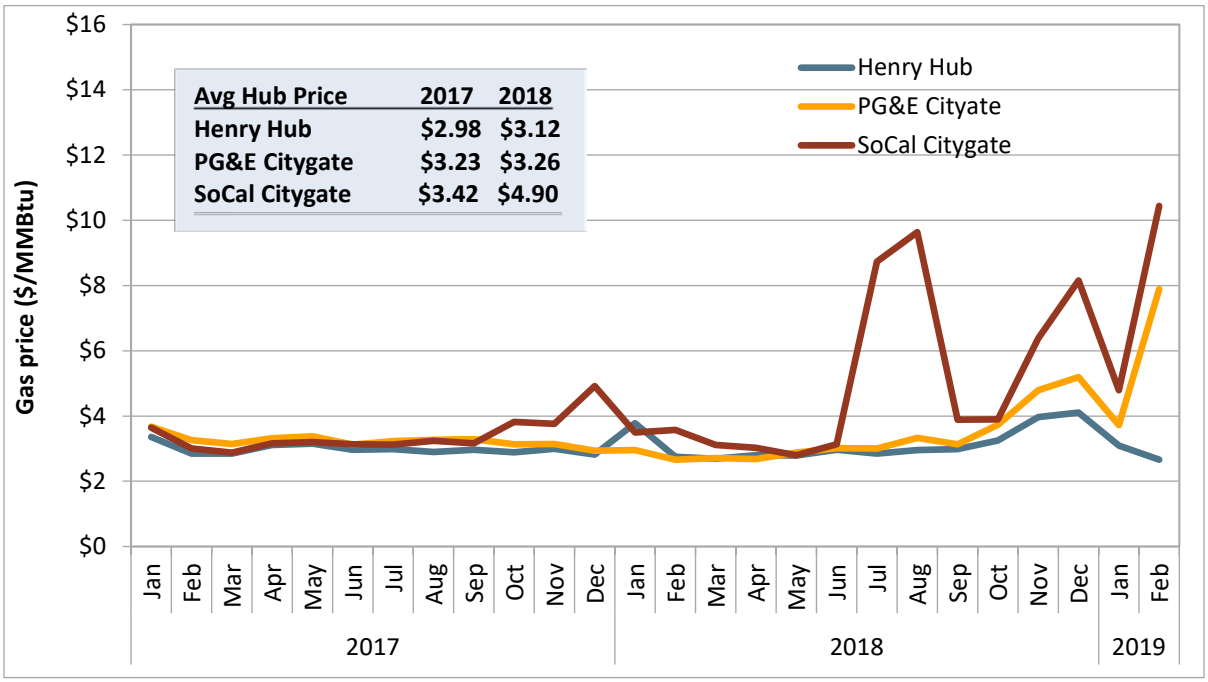


Figure 3. Monthly average natural gas prices (2017-2019)

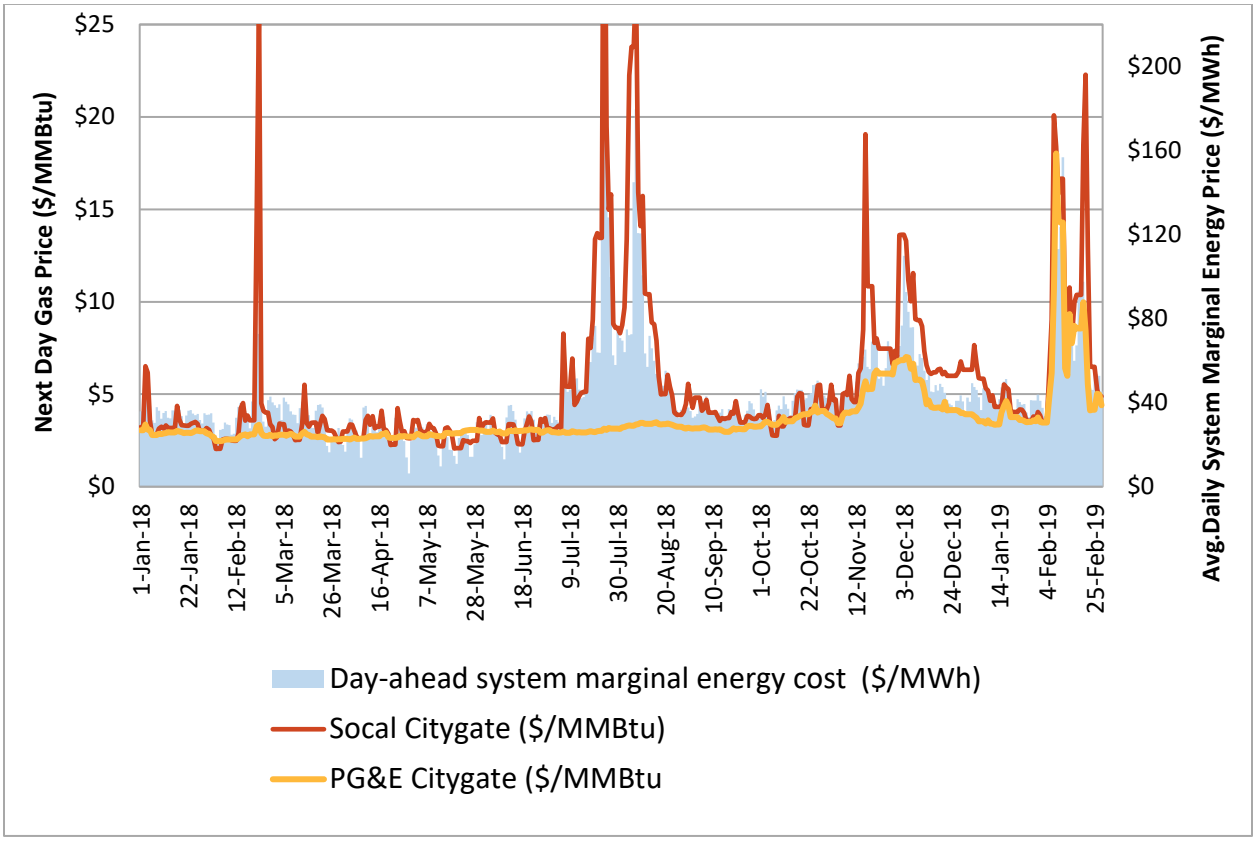


Gas prices at SoCal Citygate impacted overall system electric prices with increased frequency in 2018. There is a large amount of natural gas-fired capacity in the south, and these resources often set system-wide energy prices when there is no congestion on the major transmission paths connecting southern and northern California.

As shown in Figure 4, average day-ahead system marginal energy costs (shown in blue) are highly correlated with natural gas prices at Socal Citygate (red line). The right and left axes in Figures 4 are scaled so that the lines showing gas prices (on the left axis) correspond to the equivalent electric prices for a market heat rate of 9,000 MWh/MMBtu (on the right axis).

Thus, the close correlation between gas and electric prices in Figure 4 also shows that daily system energy prices in 2018 have tended to reflect a market heat rate of about 9,000 MWh/MMBtu based on gas prices at SoCal Citygate. This provides an indication that system energy prices were generally competitive in 2018.[2] A more detailed analysis and discussion of the competitiveness of the ISO's energy market will be included in DMM's 2018 annual report to be published in June 2019.

Figure 4. Day-ahead energy cost and natural gas prices (2018-2019)



[2] In addition to gas costs, marginal costs of gas-fired generation include cost for greenhouse gas emissions credits and O&M.