



California ISO
Shaping a Renewed Future

TECHNICAL BULLETIN

Gas Events and Market Results of February 6, 2014

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Revision History

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Contents

INTRODUCTION	4
DAY AHEAD MARKET	5
REAL-TIME MARKET	14
HOUR AHEAD MARKET.....	18
ANCILLARY SERVICES.....	20
FINAL REMARKS.....	21

Introduction

The ISO operates the bulk electric high-voltage transmission system that makes up approximately 80 percent of California’s power grid. Approximately 60 percent of the installed capacity in the ISO’s balancing authority area uses natural gas as fuel. The ISO also imports power, a portion of which is also sourced from natural gas-fired electric generating units. While the “polar vortex” weather condition that occurred in early January 2014 did not materially impact the ISO’s balancing authority, the ISO experienced certain operational challenges due to natural gas conditions arising from cold weather events in December 2013 and February 2014.

Market participants have raised a number of questions concerning how the ISO’s markets functioned during the February 6, 2014 cold weather event. This technical bulletin describes the market outcomes and their interplay with the natural gas conditions of February 6, 2014. Separately, the ISO has started a stakeholder process to examine refinements regarding how it determines commitment costs for natural gas-fired generators.¹

¹ <http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx>

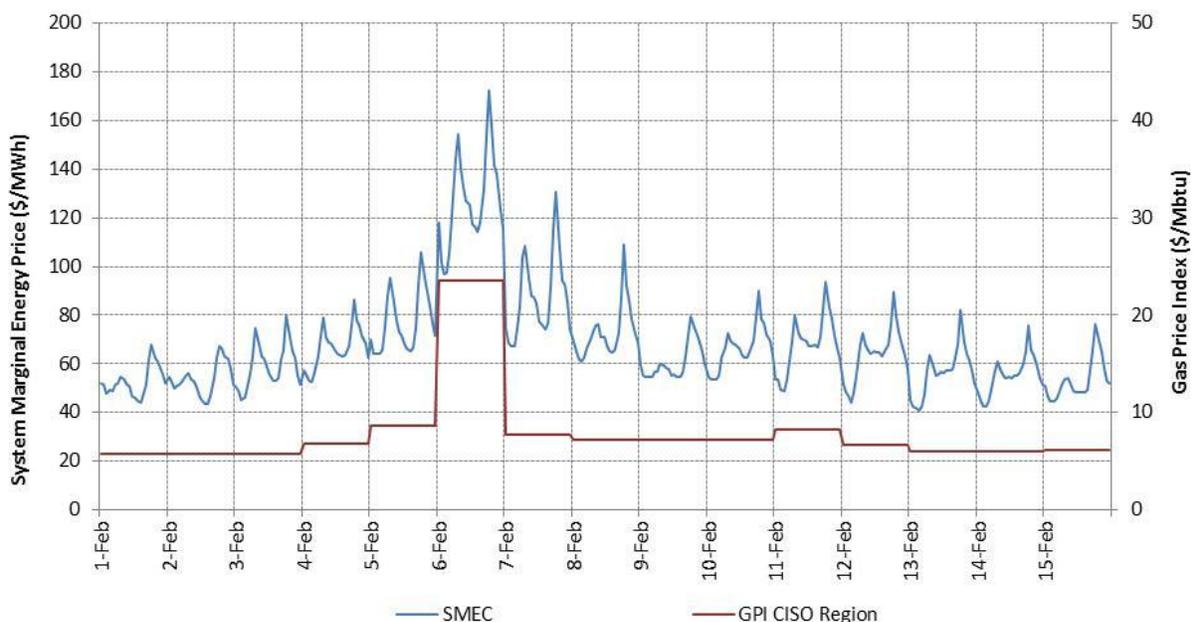
Day Ahead Market

On February 6, 2014, natural gas prices increased three-fold from approximately \$7/MMBtu the previous day to over \$20/MMBtu at some of the western trading hubs. This increase in prices appears to have been linked to a shortage of natural gas, triggered by cold weather. The increase in gas price for flow day February 6 reflected tight supply prior to the ISO day-ahead market had completed. SoCalGas informed the ISO that storage levels were near all-time lows in part because higher gas prices outside of California led to higher storage withdrawals.

In the weeks and days before February 6, the ISO monitored infrastructure outages for reliability concerns, and ensured daily gas usage reports reflecting the day market results were sent to gas pipeline operators. While the ISO had initiated efforts to enhance the granularity of the gas usage rate reports to the pipeline operator at the unit level, those changes were not in place in early February. This information will, in time, help gas pipeline operators anticipate constraints on their systems due to the expected fuel use.

Competition for gas across the west for trade date February 6 reflected more expensive gas prices and consequently increased day-ahead energy prices in the ISO market, including prices at the interties. Figure 1 shows the day-ahead energy prices for the first half of the month of February 2014 along with the California gas price index.

Figure 1: Day-Ahead energy prices in the California ISO market



The ISO uses a gas price index to calculate various generator commitment costs, including minimum load costs (MLC), start-up costs (STUC), transition costs and generated bids, as well as costs for default energy bids. The ISO uses those costs as an input to its day-ahead market in order to clear economic and feasible schedules. The gas price index for the day-ahead market run is provided the night prior to running the day-ahead market; that is, for day-ahead market for trading date of February 6, which was run on February 5 at 10am, the gas price index used was the value available and coming into the system on the night of February 4.² This gas price index was used for the February 6 trading date to calculate MLC and STUC costs for units under the proxy cost option to determine their commitment costs. Another set of resources operated under the registered cost option; such resources have their MLC and STUC calculated based on a projected monthly price and were not subject to the daily gas price changes.

For February 6, even if a more updated gas price would have been available and could have been used, only those resources under the proxy option could have relied on this higher price for their MLC and STUC. The registered MLC and STUC cannot be modified for a period of 30 days after becoming effective.³

Under the current policy as reflected in the tariff, the ISO must use at least two gas prices among Natural Gas Intelligence, SNL Daily Gas Wire, Platt's Gas Daily and Intercontinental Exchange (ICE) to calculate its gas price index for purposes of commitment costs. These indices become available as early as 10:00am and as late as 19:00pm on the day before the gas flow date; that is one day before the day-ahead trading date. Based on the availability and timing of these indices, the ISO implemented certain requirements⁴, such as using more than one gas price index. However, there is only one gas price available on the morning that the day-ahead market runs. The only gas price published prior to running the day-ahead market is the ICE index, which appears after 10:00 am and is after the day-ahead market is closed.

As a temporary measure, in March 2014 the ISO requested that FERC grant a waiver to allow the ISO to: i) rely on only one gas index from ICE under certain circumstances which is the only gas index that may be available reasonably close to the time the day-ahead market closes, and ii) switch certain resources from their registered option to proxy cost option for commitment costs in order to better reflect gas price changes as long as such resources pass the eligibility criteria for

² For the real-time market, the gas price index provided on the night of February 5 was used, and such index reflected the high gas price.

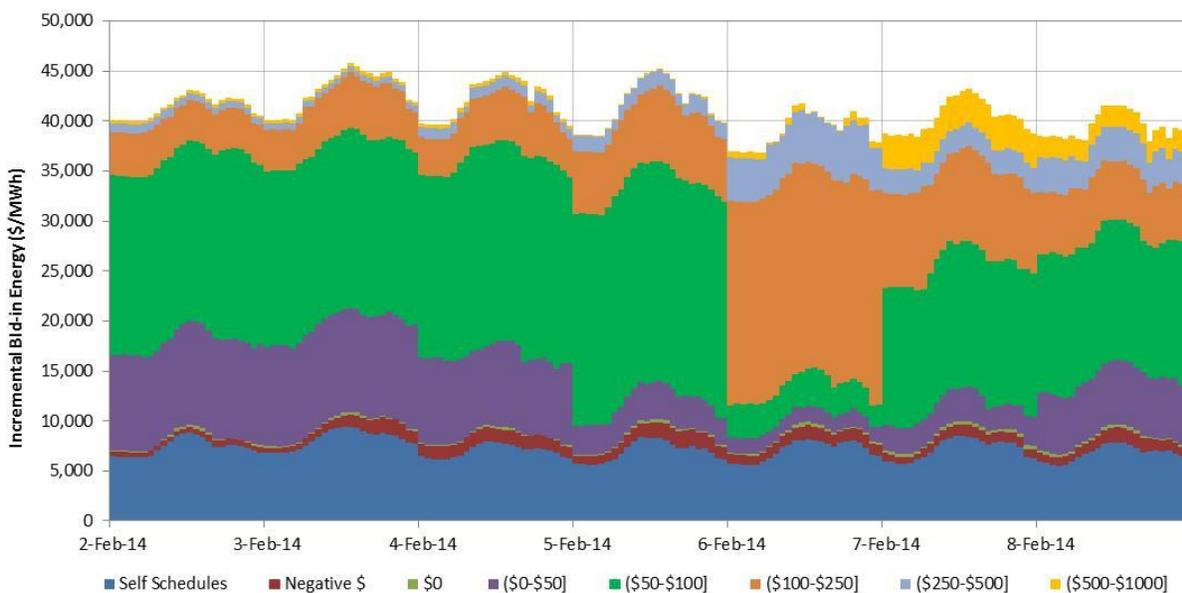
³ A generating unit with registered commitment costs may switch to a proxy cost option if fuel costs increase such that the unit's actual MLC and STUC, as calculated under the proxy cost option, exceed the unit's registered value under the registered cost option in the ISO's master file. Once the unit switches to the proxy cost option during a 30 day period, it must remain on the proxy cost option for the remainder of the current 30 day period.

⁴ Appendix C of the Business Practice Manual for Market Instruments.

switching. This temporary workaround would trigger if the ICE gas price index exceeded 150 percent of the most recent gas index available. This waiver was granted and became in effect from March 21 through April 30, 2014.⁵ IN March and April, this workaround did not trigger. The ISO is currently going through a stakeholder process for refinement of commitments costs.⁶

The day-ahead market for February 6 used a gas price index of about \$8. With gas trading on February 5th at prices over \$20, there was interplay of incremental energy bids in the least-cost solution of the day-ahead market solution. First, the MLC and STCUC of resources using the registered cost option were based on the gas future price of \$4.53 and they could not use any other gas price index even if available. Their MLC and STCUC could reflect up to 150% of the future gas price of \$4.53. Second, the MLC and STCUC for resources under proxy option reflected the daily gas price index of \$8 dollars. Third, given the flexibility to submit incremental energy bids up to the time the day market closes, multiple resources reflected the higher gas prices in their incremental energy bids, including energy bids for intertie resources, as shown in Figure 2. This figure shows a one-week trend of incremental energy bids submitted for the day-ahead market starting on February 2, 2014.

Figure 2: Incremental energy bid-in prices in the day-ahead market



⁵ *California Indep. Sys. Operator Corp.*, 146 FERC 61,218 (2014)
http://elibrary.ferc.gov/idmws/File_list.asp?document_id=14196672

⁶ More details of this stakeholder process are available at
<http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx>
www.caiso.com

These bids are organized by various price ranges. Self schedules stand for any type of self schedules; negative stands for bids lower than \$0/MWh. Bids at \$0 are tracked in a separate group; the remaining groups are for various positive price ranges, which may go up to the maximum bid price of \$1000/MWh.

Figure 3 shows the supply bid stacks. The subplot on the left shows the supply stack for average price for minimum load levels of units for all types of generation units, while the subplot on the right is the supply bid stack for all incremental energy bids, including internal generation, imports, and virtual bids. The bid stacks for incremental energy bids are a snapshot of the peak hour of the day. February 2 is depicted for comparison purposes against the bid stacks of February 6. As illustrated in these figures, the bid stack for February 6 for minimum load remained basically the same level in comparison to February 2, even though the incremental energy bid stack shows a steep increase in prices as such bids already reflected the higher gas prices.

These three factors created an abnormal outcome based on the least-cost optimization of resources for trading date February 6. With MLC and STCUC cost reflecting inexpensive gas prices in comparison to the incremental energy bids, the optimal solution dispatched more resources at minimum load instead of dispatching resources and interties on their variable operational range at higher gas prices. The ISO’s day-ahead market solution, therefore, resulted in a higher commitment of internal generation and lower dispatch levels and lower volume of net imports on the ISO’s interties.

Figure 3: Bid supply stacks (Price versus MW) in the day-ahead market

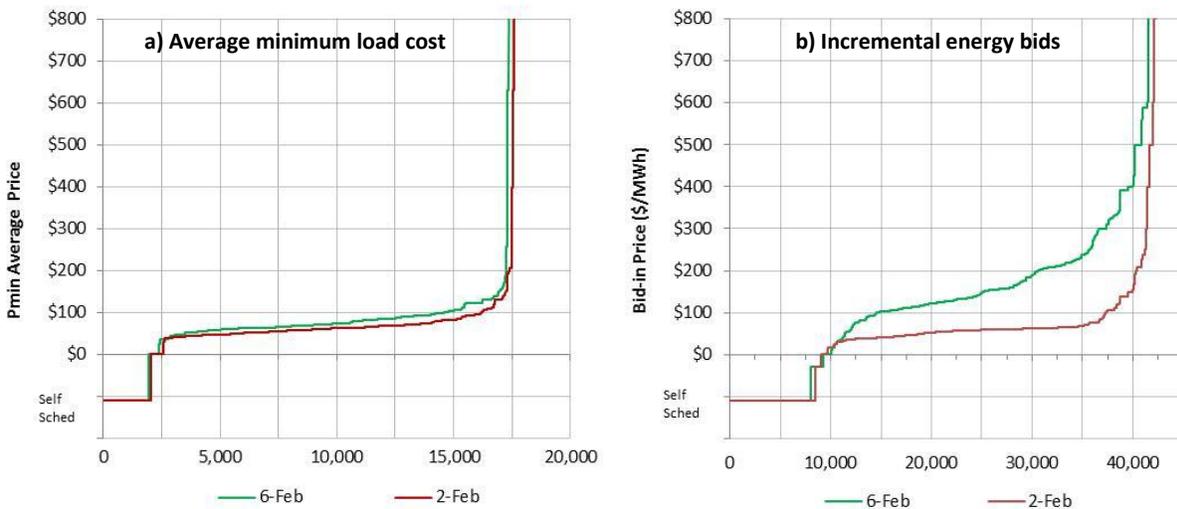


Figure 4: Volume of supply met with gas-based resources dispatched at minimum load

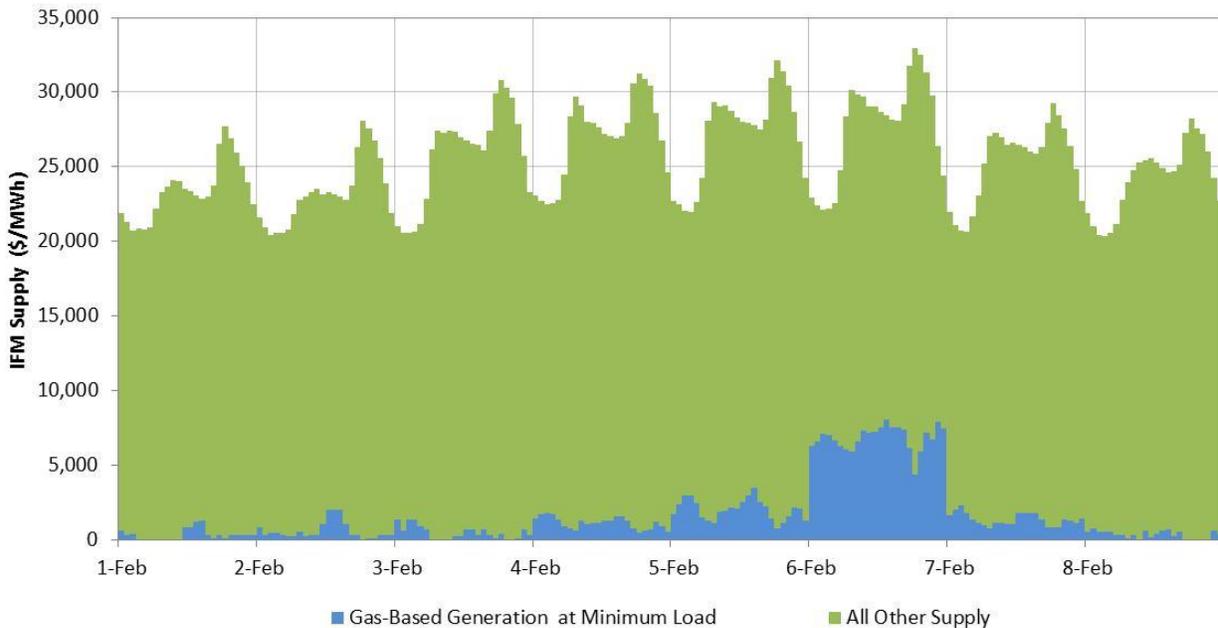
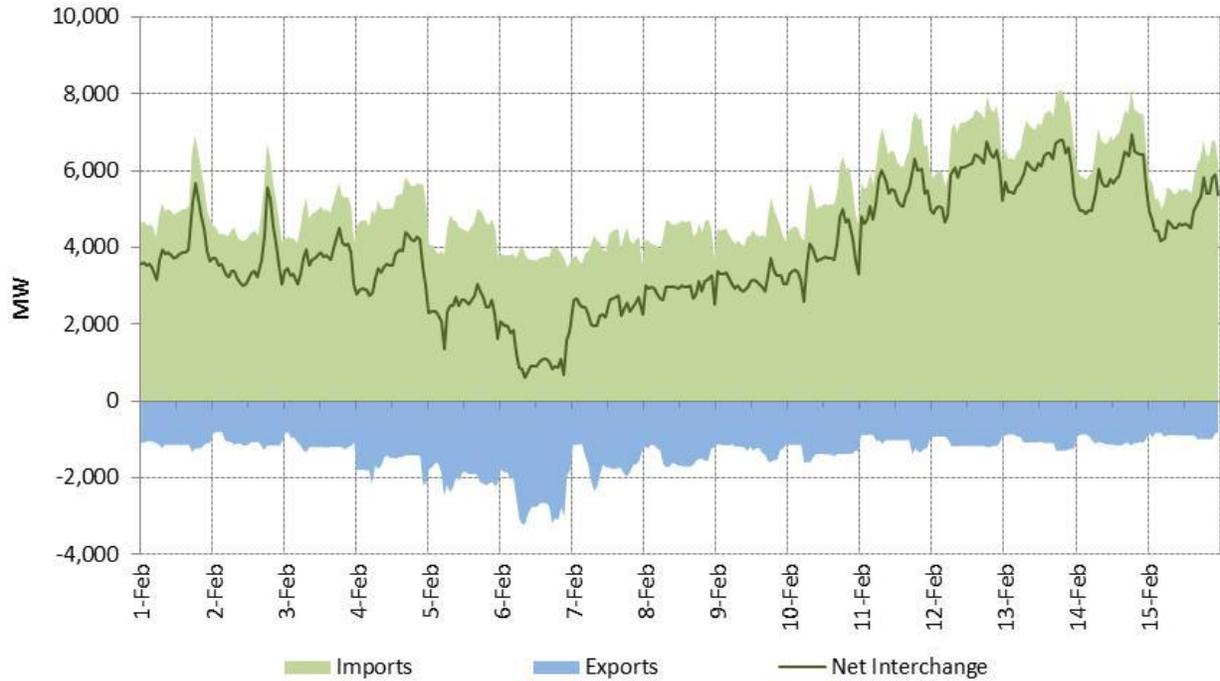


Figure 4 shows the trend of gas-based generation dispatched at minimum load for the first week of February; the area in blue shows only gas units dispatched at minimum load while the area in green account for the rest of the supply that cleared in the market. Any gas-based units self-scheduling are included in the green area because they were not dispatched at minimum load by economics. The first days of February can serve as a comparison against February 6 since these days experienced typical gas prices. Notice that once the unit is committed, the operational range becomes available and can clear through the market at higher levels.

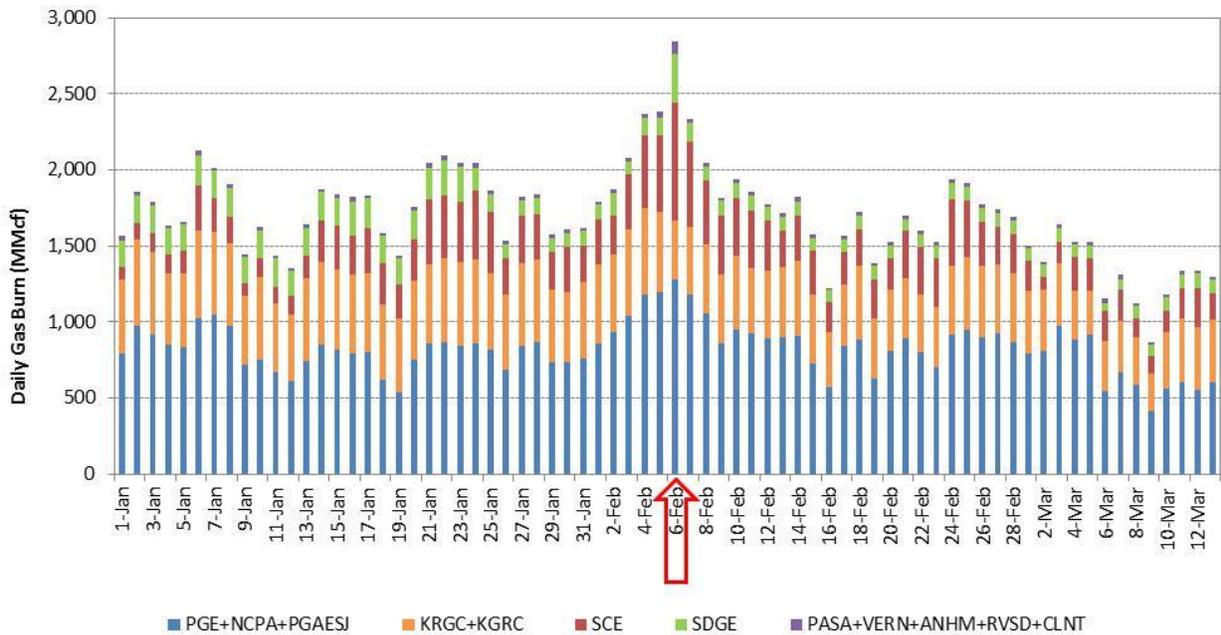
Figure 5 reflects the daily profile of day-ahead imports and exports in the ISO system during the first half of February. For February 6, more exports and fewer imports were cleared in the day-ahead market given the relatively cheaper energy from internal resources at minimum load with respect to external supply reflecting higher gas prices. After the day market run was complete at 1:00PM February 5, the gas usage projections provided to gas pipeline companies for trading date February 6 reflected a system-wide 20 percent increase with respect to the previous day's gas usage, with significantly higher projected gas usage rate in southern California than the projections reported for previous trading dates; the gas use is shown in Figure 6 and grouped by the various regions, such as PGE, SCE, SDGE and Kern River.

Figure 5: Day-Ahead intertie awards in the California ISO market



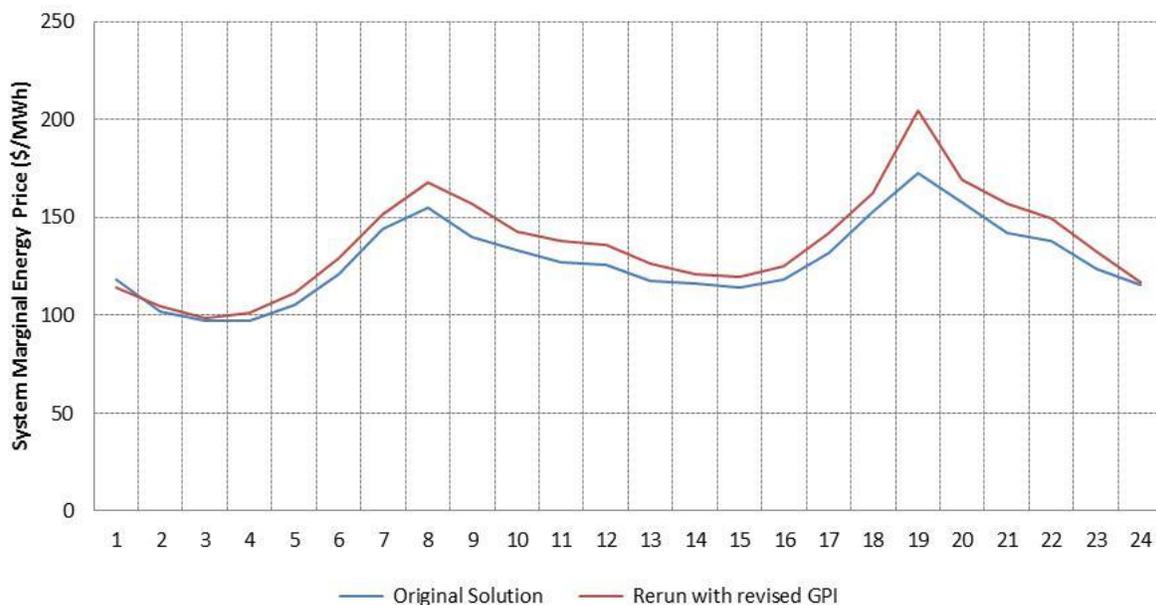
After the day-ahead market was completed, ISO real-time operators contacted gas pipelines on February 5, 2014 to inquire as to whether the gas pipeline systems were able to support day-ahead electric schedules for February 6. The ISO received an affirmative response.

Figure 6: ISO projected gas usage by electric gas-fired generation



In order to estimate the impact of having a lower gas index used in the day-ahead market for February 6, the ISO rerun the day-ahead market after the fact with MLC and STCUC that reflected the higher gas price index of about \$20. Two cases were rerun. Since only those resources under the proxy cost option would have been able to reflect the higher gas price in their costs⁷, one rerun used revised MLC and STCUC only for proxy resources to reflect the higher gas prices. This case would reflect the outcome if the ISO system had used a more recent gas price index concurrent with resources switching to proxy costs on time. The market solution was marginally different than the original solution. The main reason is that the daily gas price indices are only used for resources under the proxy cost option; those resources under the registered cost option are locked with a projected gas price index and thus their MLC and STCUC do not follow the day to day gas price changes. Figure 7 show the energy price with the results of this first rerun. The gas usage remains basically unchanged.

Figure 7: Day-Ahead energy price comparison for February 6



It is important to note that the use of a lower gas price index is not the sole element of the interplay that led to the solution of the day-ahead market for February 6th. Currently, participants have the choice of using registered cost or proxy cost for the MLC and STUC; if the registered option is taken, the MLC and STUC are calculated based on a static projected gas price that is valid for a calendar month. Only those resources that are under the proxy option are subject to the day-to-day gas price variation. So even if the ISO had been able to reflect the higher price index, only those

⁷ Few resources prior to February 6 exercised their options to switch from registered cost to proxy cost. After February 6, the ISO noticed the market of this option to switch and provided an option to expedite the switch, with 37 resources switching.

resources under the proxy option could have taken advantage of it. But on that day and as of now, multiple resources were and are under the registered cost option, under which and for effective purposes are insensitive to the gas price spikes. Based on the rerun i) the gas usage remained basically the same and ii) the system energy prices saw a 15% (\$30) increase at the peak hour.

In a second rerun, the ISO adjusted the MLC and STCUC for every gas-based unit to reflect the higher gas prices. This is a strong assumption of all units being under proxy option considering also the flexibility of being able to use the most recent gas prices. This second rerun serves as a reference of how far the day-ahead market solution could be under the most ideal instance. This also assumes that all resources would have been bidding up to their allowed cap. Figure 8 shows the supply bid stack for minimum load reflecting the adjusted MLC for higher gas prices. The supply stack for the original MLC is also shown for a reference.

Figure 8 : Comparison of supply bid stacks for minimum load

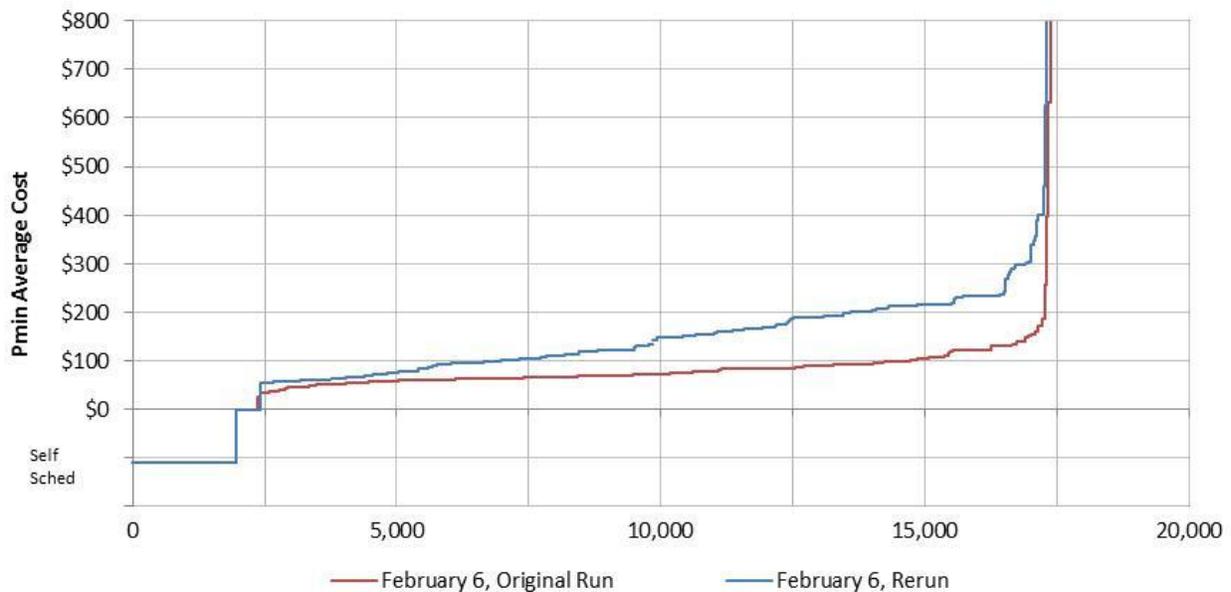


Figure 9 shows the price comparison between the original solution and this second rerun, with energy prices being higher in the rerun up to by 26% at the peak hour. Figure 10 shows the comparison of gas use between the original market solution and the rerun using higher gas prices for all gas-based units. The gas use in the rerun was about 14% less on average. The rerun also resulted in less gas-based units dispatched at minimum load, as shown in Figure 11. However, it is interesting to notice that the rerun still has a relatively high volume of supply from units dispatched at minimum load in comparison to other days that observed typical gas prices.

Figure 9 : Day-Ahead energy price comparison for February 6

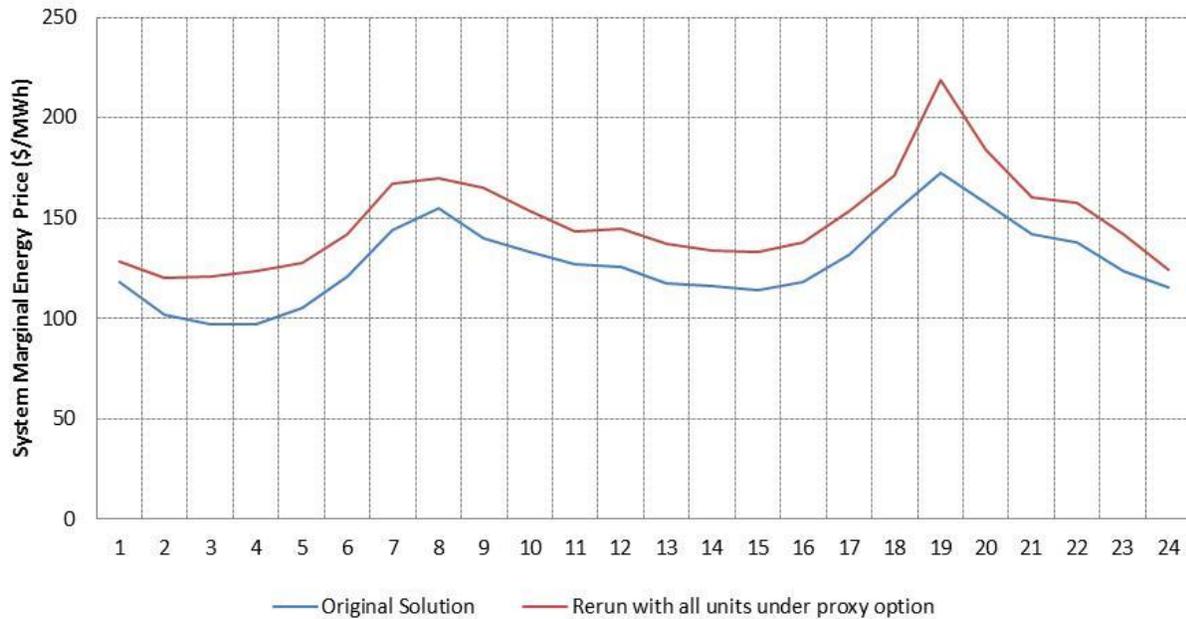
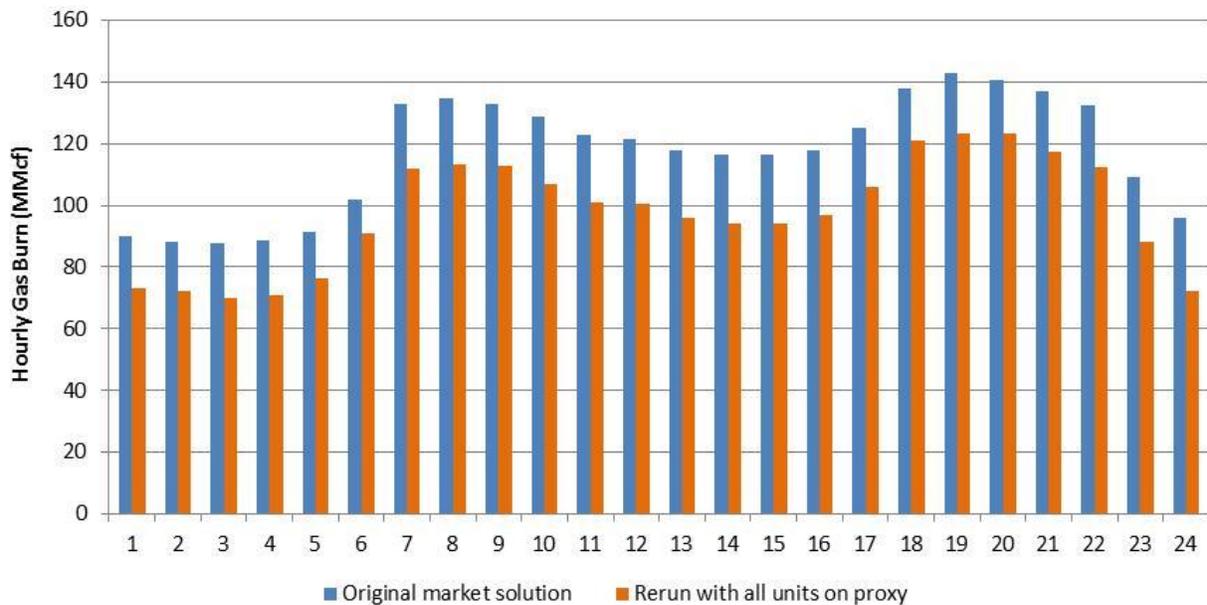


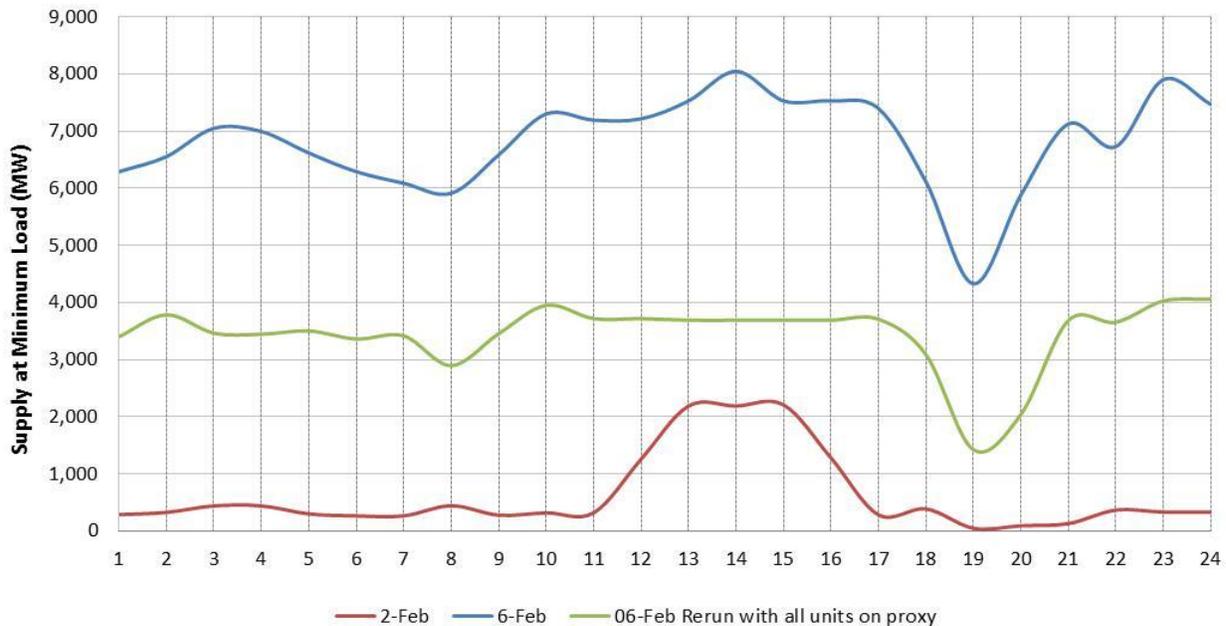
Figure 10: Comparison of gas use between runs for February 6



It is important to notice that the second rerun is based on a second level of assumptions made about resources that would have switched from registered to proxy, but the reality is that by February 5 when the day-ahead market was run such switching from registered to proxy did not take place. As of now many resources are still under registered cost option, and for one or another reason this is the option they have chosen to manage their risk under the current paradigm even

under periods of volatile gas prices.⁸ The use of higher gas prices for February 6 would have not resulted in a materially different solution. The ISO is cognizant of the implications of having MLC and STCUC relying on gas price indices with one day lag, and has launched a stakeholder process to refine its process.⁹

Figure 11: Comparison of gas-based units dispatched at minimum load



Real-Time Market

Early on February 6, 2014, ISO real-time operators contacted gas pipelines to reconfirm that they could support the electric schedules for February 6, 2014. Again, the ISO received an affirmative response. But, before 7 a.m., SoCalGas contacted the ISO with concerns over generating units’ gas usage rates. The ISO also received forced outage notifications from generating units based on gas usage limitations imposed by SoCalGas. Soon thereafter, SoCalGas directed that all generating units located in the southern portion of its system not increase their current natural gas usage rates.

As a result, the ISO also issued exceptional dispatches to generators to ensure they did not increase their gas usage rate, consistent with SoCalGas’ directive. These exceptional dispatches included decreasing output from some resources taking service from SoCalGas. ISO real-time

⁸ After the ISO expedited a switching from registered option to proxy option, 39% of gas-based resources were under full proxy option, which represents a total minimum load of 5,130 MW.

⁹ More details of this stakeholder process are available at <http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx>

operators then dispatched other generating units and intertie resources to make up for the loss of electric supply. Figure 12 shows the daily profile of exceptional dispatches (ED) and reflects the absolute sum of all exceptional dispatches (incremental plus decremental) during the applicable timeframe, including decreased output from certain resources and increased output from other resources.

Figure 12: Daily exceptional dispatch by reason

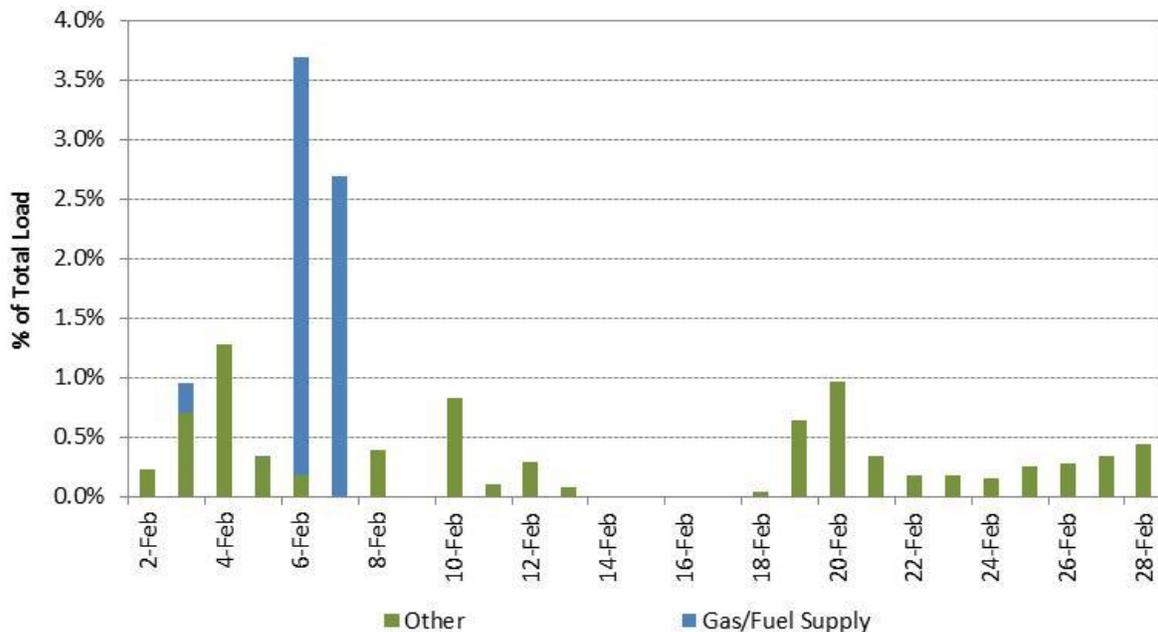
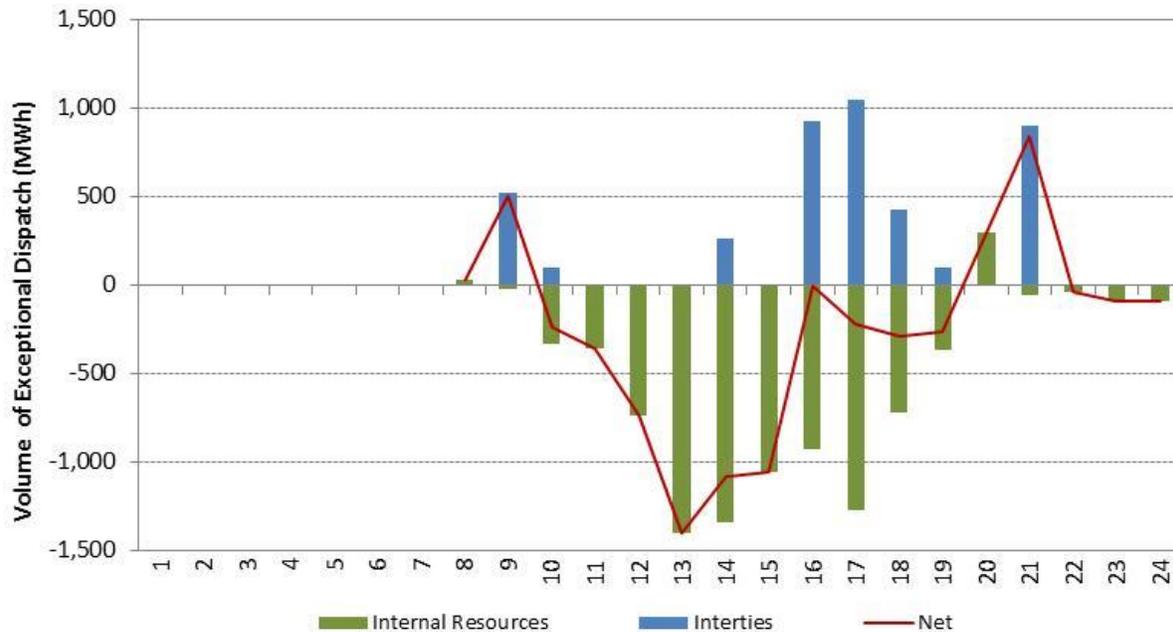


Figure 13 shows the hourly trend of exceptional dispatches; this is grouped into internal resources and interties. The majority of exceptional dispatches were decremental since the output for multiple gas-based units in the south were limited to manage the gas usage. With concerns of limited supply with the projected evening peak, the ISO acquired intertie energy through exceptional dispatches in the real-time market in order to secure more imports. The negotiated price of the exceptional dispatch on ties was on average about \$250.

Some participants raised concerns that the data posted on OASIS regarding exceptional dispatches did not include EDs for interties. Exceptional dispatches for interties are not currently included on OASIS. The ISO expects to improve the OASIS report after the implementation of the Spring release to reflect the interties EDs as well. However, it is important to note that the ISO provides another mechanism to report the exceptional dispatches, including interties. As per FERC order ER08-1178, the ISO issues on a monthly basis two ED reports¹⁰.

¹⁰ Exceptional Dispatch reports, namely Table I and Table II, contain specific details of all exceptional dispatches issued during a given month, including (1) Megawatts (MW); (2) Commitment; (3) Inc or Dec; (4) Hours; (5) Begin Time; (6) End Time; (7) Total Volume (MWh); (8) Min Load Cost; (9) Start Up Cost; (10) CC6470; (11) ED Volume (MWh INC/DEC); (12) CC6470 INC; (13) CC6470 DEC; (14) CC6482; (15) CC6488; and (16) CC6620. Exceptional Dispatch reports are available through the ISO public website at <http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=240C755B-777E-4816-A75C-80C0702E7F8D>

Figure 13: Hourly exceptional dispatch by type of resource

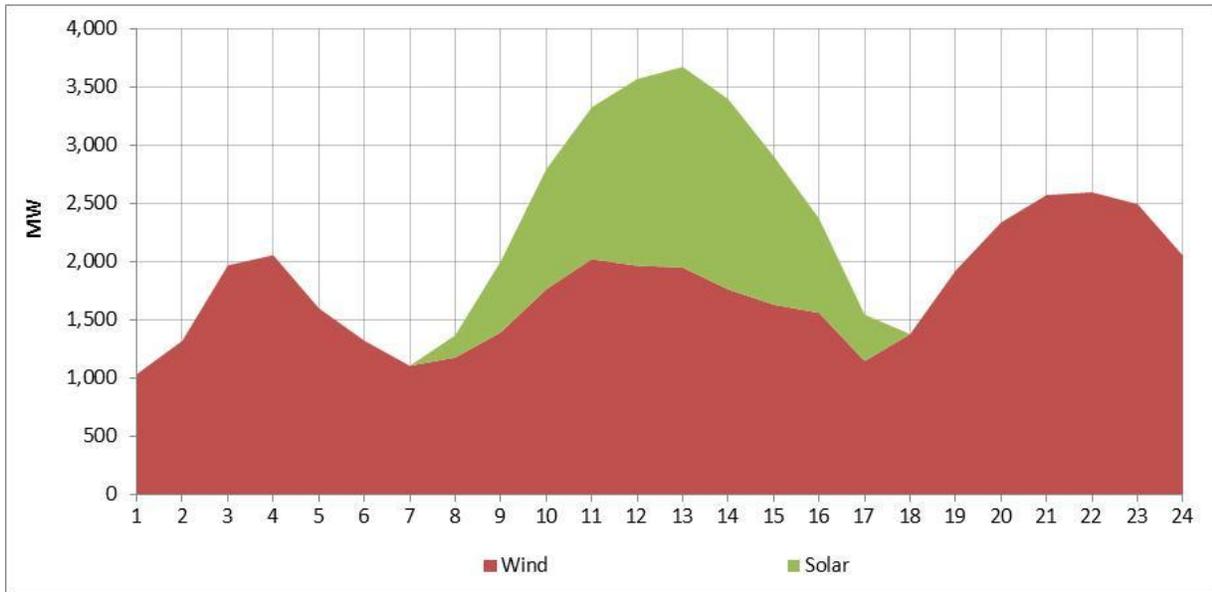


In addition to repositioning generating units on the SoCalGas system and securing more imports, the ISO issued a system wide Flex Alert, which consists of a general public appeal for conservation. Also, the ISO issued a grid warning notice at 13:00, explaining the gas use constraint; this grid warning notice also encouraged market participants to offer additional energy and ancillary service bids. The grid warning terminated at 22hrs.

The ISO also contacted utility distribution companies to request that they activate their interruptible load. Currently, the ISO calls for demand response manually and outside the market through procedure 4420 and then utilities call for demand response programs with consumers that have contracts for demand response. All demand response combined provided approximately 800 MW during the evening ramp and peak of the electric demand, which effectively reduced the system load by that amount, relieving pressure on the supply. These interruptible load programs are outside the market and, therefore, cannot set the market prices, opposite to have demand response being dispatched through the market to manage the load through DR bids and awards.

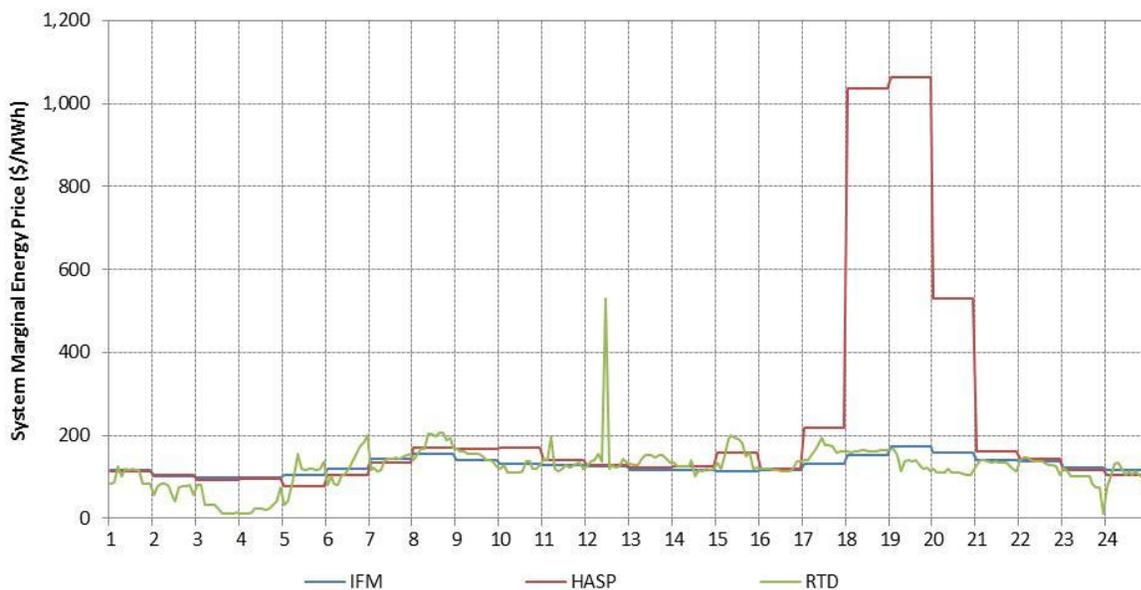
The WECC Reliability Coordinator also issued Energy Emergency Alerts to initiate its own efforts to help mitigate the system conditions. In the late afternoon, wind generation output increased as evening peak electric demand occurred, as shown in Figure 14. This output further reduced the need for additional gas-fired generation to meet this demand and relieved pressure on the overall supply side.

Figure 14: Wind and solar production on February 6



After the evening electric peak, the ISO informed the utilities that they could restore interruptible loads and terminated its Flex Alert and grid warning notice. For February 7, 2014, the ISO re-issued a restricted maintenance outage notice as a precaution in case conditions on the gas system did not stabilize. On February 6th, all markets observed higher prices than usual since gas-based units as well as imports did have more expensive incremental energy bids. Prices across the various ISO markets are shown in Figure 15.

Figure 15: System marginal energy price across ISO markets

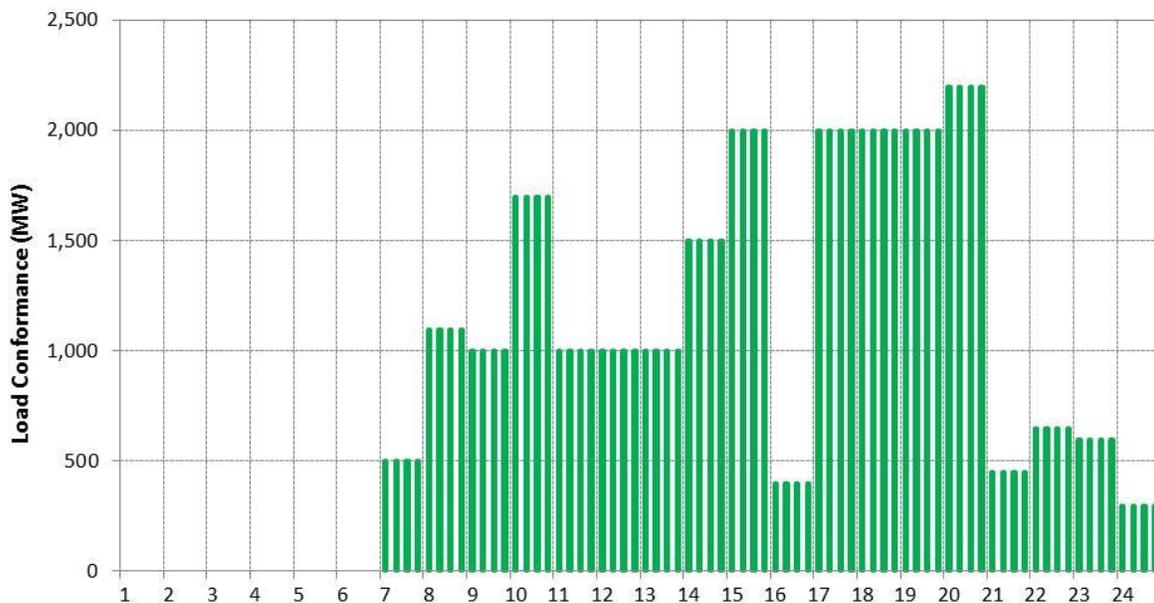


One concern raised for this day is the real-time prices not reaching levels beyond \$200. As explained through the document, there are three main factors at play: demand response help to shave the load across the evening ramp and peak, ii) the wind generation picked up just right around the evening peak, and iii) given the projected tight conditions for the peak the ISO secured more interties to position the system for the evening peak. All these factors combined resulted in less demand and more supply available that help manage the gas supply limitations and that also resulted in the system clearing at a lower level in the supply stack that resulted in such prices.

Hour Ahead Market

Given the supply limitations and significant uncertainties due to the gas shortage, the meet energy peak needs on February 6 the ISO increased its procurement of imports in the Hour Ahead Pre-dispatch (HASP) market. ISO operators made upward adjustments, as shown in Figure 16, to the projected load levels in the hour-ahead to prevent potential reliability problems from occurring in real time as the Hour-Ahead is the last opportunity to secure external supply.

Figure 16: Load conformance in the HASP market on February 6



Given the stressed conditions, the HASP market solution for HE18 and 19 resulted also in reducing exports; however, the awards reflecting those reductions were declined accordingly by their scheduling coordinators, thereby negating the reduction in exports. The ISO did not materially curtail any exports on February 6. Figure 17 shows the total exports awarded in HASP together with the reduction of exports occurring in HASP that were subsequently declined.

Figure 17: Hourly profile of exports cleared in HASP

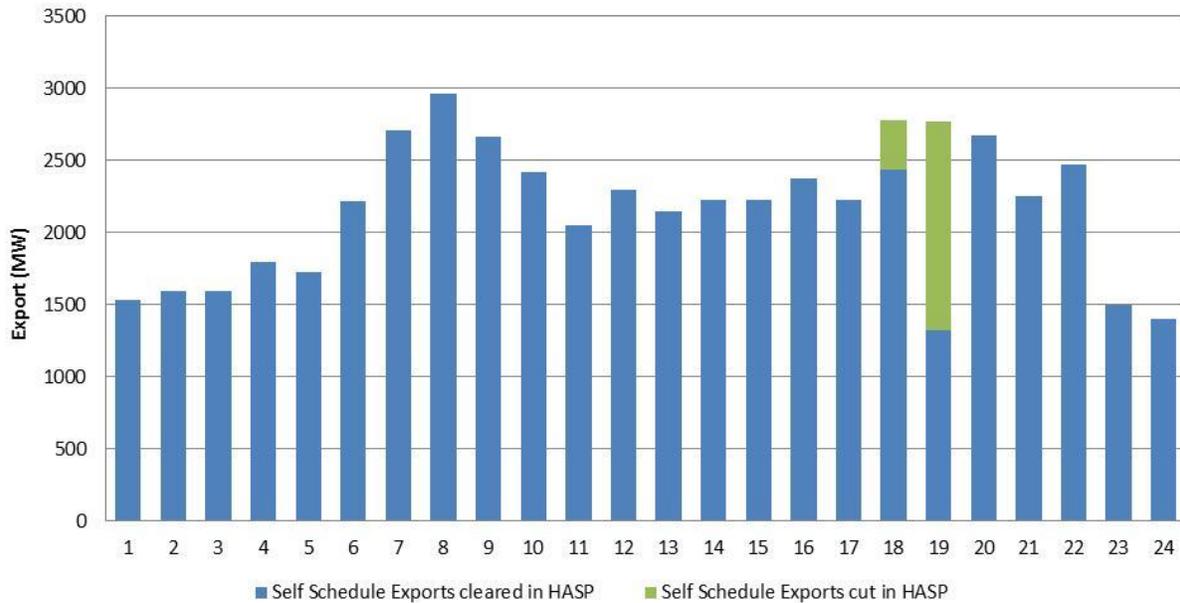
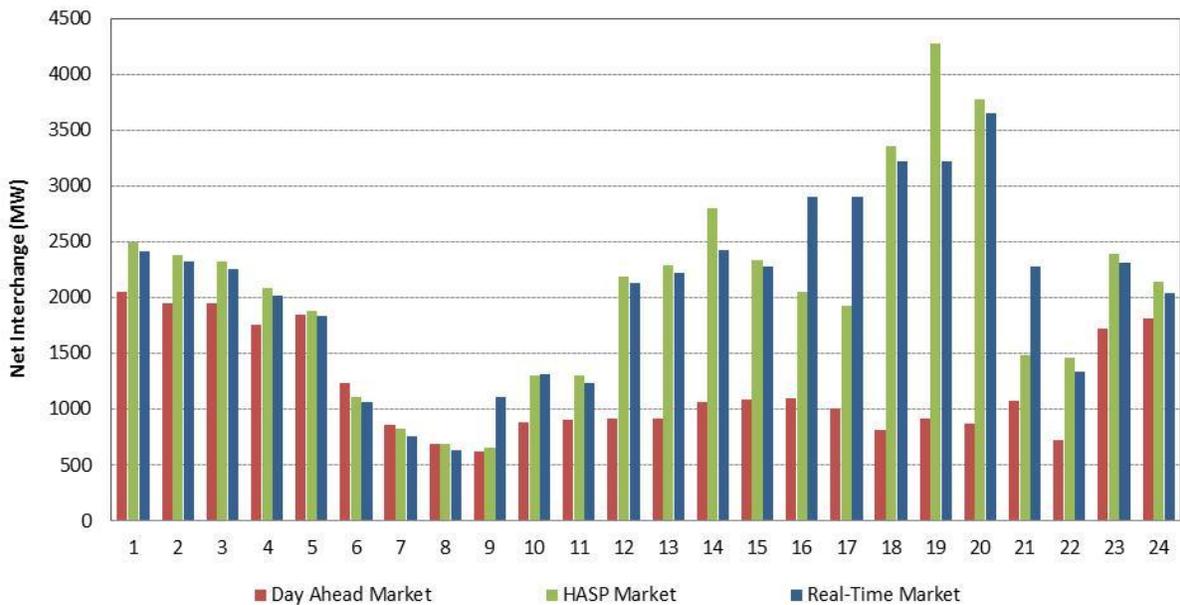


Figure 18 shows the hourly profile of net imports cleared in the day-ahead market, the HASP market and the actual imports coming into the real-time. The real-time market values include any exceptional dispatches at the interties.

Figure 18: Hourly profile of net imports



Ancillary Services

In order to meet its ancillary service (AS) requirements, the ISO procures ancillary services procured from SP26 region; this region comprises resources in Southern California. On February 6, the NP26 expanded ancillary service region was activated due to gas supply concerns in southern California. With this activation, the ISO relieved the pressure of procurement of reserves in the south and instead relied on procurement from the north.

Ancillary services scarcity pricing was triggered in the real-time pre-dispatch (RTPD) market run for hour ending 17 and in the hour-ahead scheduling process (HASP) market for hour ending 18 and 19. The following table provides the details on the services impacted and quantities:

Table 1: AS Scarcity triggered on February 6

Market	Hour Ending	Interval	Ancillary Service	Ancillary Service Region	Shortfall (MW)	Percentage of Requirement
RTPD	17	1-3	Non-Spin	AS_NP26_EXP_P	60.5	7%
RTPD	17	1-3	Reg Down	AS_NP26_EXP_P	61	20%
RTPD	17	4	Reg Down	AS_NP26_EXP_P	1	0.4%
HASP	18	-	Non-Spin	AS_NP26_EXP_P	208	21%
HASP	18	-	Reg Down	AS_NP26_EXP_P	17	6%
HASP	19	-	Non-Spin	AS_NP26_EXP_P	95	12%

Final Remarks

Based on outcomes from February 6, the ISO continues to work with natural gas pipeline operators to improve communications and awareness between real-time operators of the ISO and pipeline systems.

Among the lessons learned from the February 6 cold weather events was that gas prices used for the calculation of generating unit MLC and STCUC may not reflect the current gas price in the event of a sudden gas price spike. This is because the ISO uses gas market indices that are based on gas trades the day prior to the ISO's day-ahead market. As a result, the ISO's market committed resources in the day-ahead market that reflected the lower gas prices traded the previous day. This created concerns because the situation resulted in an inefficient dispatch that did not accurately reflect generation production costs.

To address this issue, the ISO requested, and the Commission granted, temporary waivers of its tariff to allow the ISO to incorporate a more recent gas price forecast into its day-ahead market solution as well as settlement practices under certain conditions, including the option for registered-cost resources to switch to proxy cost option when gas price spikes occur. The time period for those waivers has expired. The ISO is now undertaking a stakeholder process to explore refinements to its market rules. The ISO plans to include this item in the agenda of the upcoming Market Performance and Update Forum on May 22, 2014.