California Independent System Operator Corporation

California ISO

Q1 2013 Report on Market Issues and Performance

May 29, 2013

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Executive summary

This report provides an overview of general market performance during the first quarter of 2013 (January – March) by the Department of Market Monitoring (DMM). Key trends highlighted in this report include the following:

- The ISO energy market prices increased with implementation of the state's greenhouse gas cap-and-trade program. DMM estimates prices in the first quarter of 2013 increased about $6.15/MWh with implementation of this program.[1] 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 during this period.[2]
- Average day-ahead and real-time system energy prices tracked closely. However, hour-ahead prices continued to be significantly lower than day-ahead and real-time system energy prices during many periods.
- Congestion continued to impact overall energy prices, raising prices in the Southern California Edison area by over 8 percent while lowering them in other areas. Most of this price impact was driven by congestion on the SCE_PCT_IMP_BG constraint, which limits the amount of load within the SCE area that can be met by flows into this area.
- Congestion in the day-ahead and real-time markets was much more consistent, on average, which helped to lower real-time congestion imbalance offset charges notably.
- Exceptional dispatch energy and costs were significantly lower. This drop reflects a seasonal trend as well as ISO efforts to reduce exceptional dispatches.
- Overall bid cost recovery payments decreased slightly compared to previous periods, despite higher bid cost recovery payments for resources committed through the residual unit commitment process.
- Convergence (or virtual) bidding was slightly unprofitable overall during the first quarter, which represents the first quarter in which virtual bidding was not profitable since it was implemented in February 2011. This likely reflects better convergence between the day-ahead and real-time energy prices and more consistency of day-ahead and real-time congestion.
- Flexible ramping constraint costs totaled around $10 million in the first quarter compared to $20 million in all of 2013. This is the result of a combination of increases in the procurement requirement for this constraint set by the ISO, the frequency of this constraint binding and shadow prices when this constraint binds.

Energy market performance

This section provides a more detailed summary of energy market performance during the first quarter.

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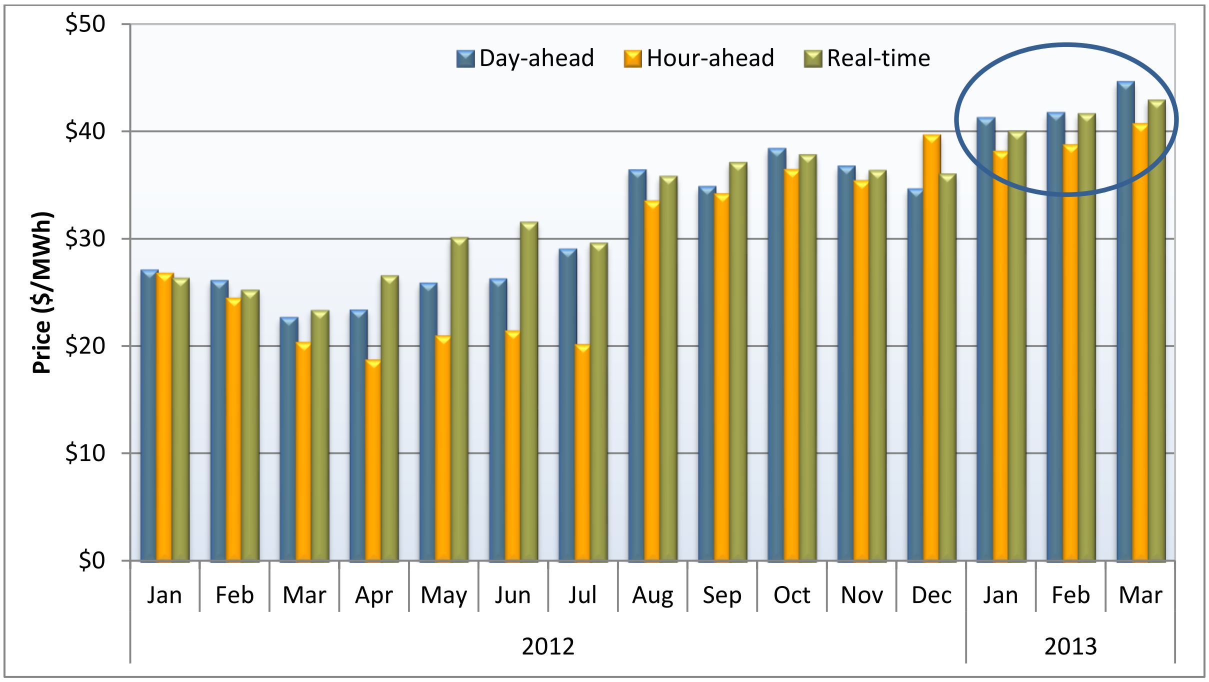
[1] The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the CPUC and other state entities. Under a recent CPUC decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs. More detailed information on this issue is provided in Section 3.1 of this report.

[2] The cost of allowances for emitting one metric ton of greenhouse gas averaged about $14.55 during the first quarter of 2013. For a relatively efficient unit with a heat rate of 8,000 Btu/kWh, this represents an additional cost of about $6.19/MWh ($14.55/mtCO_2e x 0.053165 mtCO_2/MMBtu x 8,000 Btu/kWh = $6.19/MWh).

Price levels increase as cap and trade is implemented. Average system energy prices in the ISO markets were higher in the first quarter compared to the fourth quarter of 2012 (see Figure E.1). This increase is primarily the result of implementation of the state's cap-and-trade program. DMM estimates that the cap-and-trade program has added about $6.15/MWh to the day-ahead system energy price. A more detailed discussion of this is provided in Section 3.1 (pp. 41-48) of this report. The increase in prices beginning in spring 2012 was primarily the result of increasing natural gas prices and other factors not related to the cap-and-trade program.

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



Continued convergence of average system energy prices between day-ahead and real-time. Average system energy prices in the real-time market (excluding congestion) were relatively close to average prices in the day-ahead market (see Figure E.1). This trend was driven in part by a decrease in the frequency of extreme real-time price spikes for system energy resulting from short-term limitations in upward ramping capacity.

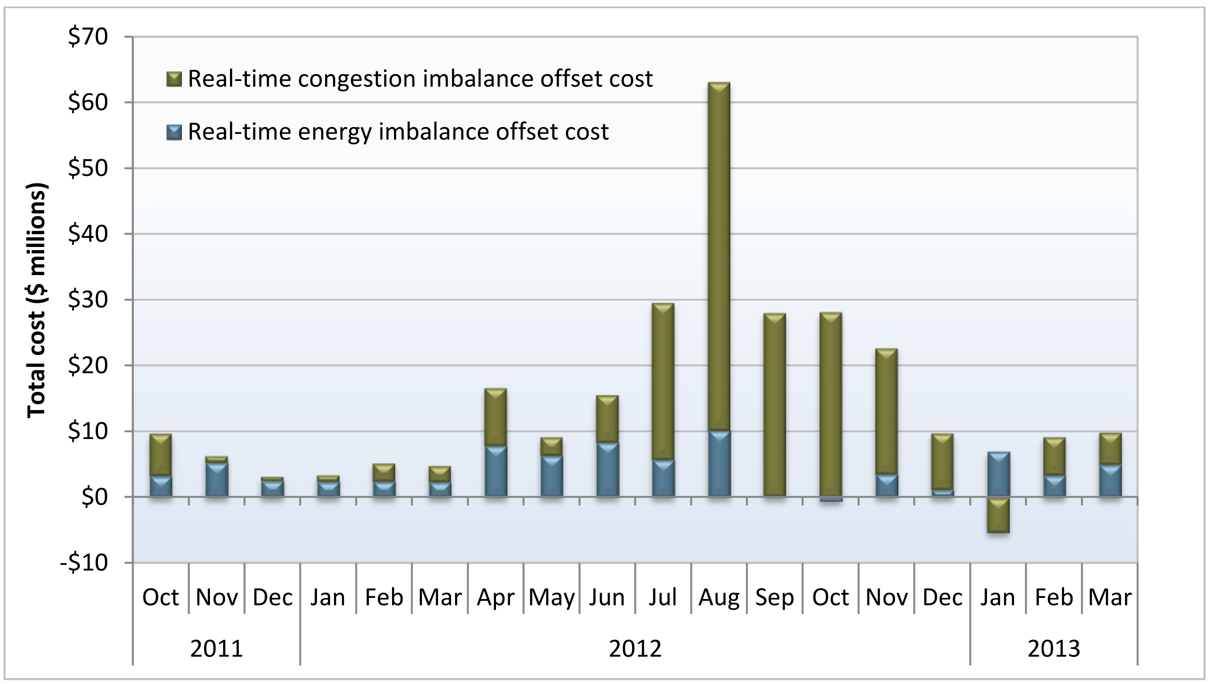
Continued divergence between hour-ahead and real-time system energy prices. Average system energy prices in the hour-ahead market were lower than real-time prices in each month in the first quarter, as seen in Figure E.1. These differences occurred most frequently in the evening ramp down period and early morning hours.

Congestion continued to affect day-ahead and real-time prices. Congestion within the ISO system continued to impact overall prices in the first quarter in the day-ahead and real-time markets. Congestion increased average day-ahead prices in the Southern California Edison area by over 8 percent and real-time prices by almost 10 percent. For the quarter, congestion caused comparable decreases in the average prices for the San Diego Gas & Electric and Pacific Gas and Electric areas. Most of this price impact was driven by congestion on the SCE_PCT_IMP_BG constraint, which limits the amount of load within the SCE area that can be met by flows into this area.

More consistent overall congestion effects in day-ahead and real-time markets. Congestion tends to occur more frequently in the day-ahead market, but with lower congestion prices. In the real-time market, congestion prices are often substantially higher when a constraint is binding. Together, these factors can cause congestion to differ between the day-ahead and real-time markets on an hourly basis. However, when taken together, the total effect on average day-ahead and real-time prices was much more consistent in the first quarter of 2013 than in previous quarters.

Real-time congestion imbalance offset costs fell. Real-time congestion imbalance costs totaled about $5 million in the first quarter (see Figure E.2). This is down significantly from about $56 million in the fourth quarter of 2012. These costs fell, in part, as the ISO continued efforts to address systematic differences between the day-ahead and real-time models. However, real-time imbalance energy offset costs increased from an all-time low of around $4 million in the fourth quarter of 2012 to around $15 million in the first quarter. This first quarterly value was more consistent with levels observed in 2012, and reflects a trend of hour-ahead prices that were systematically lower than prices in the 5-minute real-time market.

Figure E.2 Real-time imbalance offset costs



Exceptional dispatch energy and costs decreased. Total energy and commitment from exceptional dispatches fell by about 45 percent while costs fell by about 29 percent compared to the first quarter of 2012. Total energy from exceptional dispatches, including minimum load energy from unit commitments, equaled 0.19 percent of system loads in the first quarter of 2013, compared to 0.35 percent in the first quarter of 2012. Total above-market costs from exceptional dispatch decreased from $5.1 million in the first quarter of 2012 to $3.6 million in the first quarter of 2013. These declines were partly attributable to ISO efforts to reduce exceptional dispatch volumes.

Bid cost recovery payments for residual unit commitments remained high. Total bid cost recovery payments in the first quarter were about $21 million, down from $28 million in the fourth quarter.

However, while overall costs decreased, residual unit commitment bid cost recovery remained high at around $6 million. This is comparable to the fourth quarter level, but substantially higher than during other prior periods. Direct residual unit commitment costs also remained high at about $1 million for the quarter, compared to about $2 million for all of 2012. This continued high level of residual unit commitment costs resulted in part from ISO efforts to decrease the amount of exceptional dispatches. Specifically, ISO operators increased system or regional residual unit commitment requirements, primarily in peak hours, to commit additional capacity that could mitigate potential capacity and ramping contingencies.

Convergence bidding

Convergence bidding activity was marked by several key trends in the first quarter.[3]

Increased convergence bidding designed to take advantage of congestion. Market participants can speculate on (or hedge) potential congestion between points within the ISO system by placing an equal amount of virtual demand and supply bids at different internal locations during the same hour. This type of offsetting virtual position at internal locations accounted for an average of about 1,240 MW of demand bids offset by over 1,240 MW of virtual supply bids at other locations per hour in the first quarter. These offsetting bids represented over 73 percent of all cleared bids in the first quarter, up from 60 percent in the fourth quarter. The non-overlapping cleared positions averaged around 225 MW of virtual demand, down from around 350 MW in the previous quarter.

Decreased net revenues associated with congestion related convergence bidding positions. In total, convergence bidding entities lost almost $3 million in net revenues in the first quarter, which was down from positive revenues of about $15 million in the fourth quarter. Most of the losses were associated with offsetting virtual supply and demand positions taken by entities engaging in pure financial trading that do not serve load or transact physical supply (see Table E.1). Entities that engage in the market as physical generation and load made small revenues in the first quarter.

Table E.1 Convergence bidding volumes and revenues by participant type (January – March)

Trading entities	Average hourly megawatts			Revenues ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	373	309	681	-7.0	4.8	-2.1
Marketer	61	57	119	-1.1	0.0	-1.1
Physical Generation	10	18	28	0.0	0.3	0.3
Physical Load	0	5	5	0.0	0.1	0.1
Total	**445**	**389**	**834**	**-8.1**	**5.2**	**-2.8**

[3] Convergence bidding was first implemented in February 2011. On November 2011, convergence bidding was temporarily suspended on inter-tie nodes. On May 2, 2013, FERC made this decision permanent under certain conditions. See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. See 143 FERC ¶ 61,157 (2013) conditionally accepting elimination of inter-tie convergence bidding. In the May 2013 order, FERC indicates that the ISO should address within a year the issue of structural separation between hour-ahead and real-time market prices or explain why it has not done so before it reevaluates the efficiency of convergence bidding on inter-ties. More information can also be found under FERC docket number ER11-4580-000.

Special issues

Effect of cap and trade on ISO markets

Resources in the ISO market became subject to the state's greenhouse gas cap-and-trade program in January 2013. In Section 3.1 of this report DMM examines the impacts of these compliance costs using several approaches (see pp. 41-48). First, analysis by DMM indicates that in the first few weeks of 2013 the majority of energy bids for gas increased by less than $10/MWh, which is consistent with additional cost of emission allowances needed to comply with these program requirements for various types of generating units.[4] Based on statistical analysis of the change in day-ahead energy prices in 2013, DMM estimates that the average wholesale electricity price impact is about $6.15/MWh.[5] This is also highly consistent with the additional emissions costs for gas units typically setting prices in the ISO market. In addition, analysis by DMM shows that imports increased in the first quarter of 2013 by 10 percent compared to the first quarter of 2012. This suggests that overall imports have not decreased as a result of the program.

Flexible ramping constraint performance

The flexible ramping constraint is designed to help mitigate short-term deviations in load and supply between the real-time commitment and dispatch models (e.g., because of load and wind forecast variations and deviations between generation schedules and output). The constraint procures ramping capacity in the 15-minute real-time pre-dispatch that is subsequently made available for use in the 5-minute real-time dispatch. Total payments made for flexible ramping capacity during the first quarter were about $10 million, the largest quarterly value since the constraint was implemented in December 2011. By comparison, payments for spinning reserve totaled about $6 million for the same period.

ISO operators continued to increase the flexible ramping requirement more consistently during the morning and evening ramping periods of the day in the first quarter. This caused increases in the procurement level, the frequency that this constraint binds and the shadow prices for this constraint when it binds. Together, these factors caused the flexible ramping payments to increase. The ISO has begun a review of how the flexible ramping constraint has affected unit commitment decisions made in real-time and initial results have found that effective capacity was added to meet the requirement. DMM believes this review is an important measure of the overall effectiveness of the constraint and is working with the ISO to further review and analyze the results.

[4] The ISO's greenhouse gas allowance price index rose to over $16/mtCO$_2$e during the first week of January 2013 but then dropped to about $14/mtCO$_2$e during the second week of January 2013. A price of $14/mtCO$_2$e equates to an additional cost of about $6/MWh for a relatively efficient unit with a heat rate of 8,000 Btu/kWh. A price of $16/mtCO$_2$e equates to an additional cost of about $10/MWh for a less efficient unit with a heat rate of 12,000 Btu/kWh.

[5] The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the CPUC and other state entities. Under a recent CPUC decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs. More detailed information on this issue is provided in Section 3.1 of this report.

1 Market performance

This section highlights key indicators of market performance in the first quarter. These include the following:

- Continued improvement in system day-ahead and real-time price convergence, particularly in peak hours.
- Continued divergence between system energy prices in the hour-ahead market for imports and exports, compared to prices in the 5-minute real-time market.
- Decreased frequency of real-time price spikes.
- More consistency of congestion between the day-ahead and real-time markets, on average.
- Reduced real-time imbalance costs, driven by lower congestion imbalance offset costs.
- Reduced energy and costs from exceptional dispatches.
- Increased residual unit commitments resulting from the use of this process in place of exceptional dispatches to commit additional capacity.
- Slightly lower overall bid cost recovery payments, despite increased bid cost recovery payments resulting from residual unit commitments.

1.1 Energy market performance

This section assesses the efficiency of the energy market based on an analysis of the system energy component of day-ahead, hour-ahead and real-time market prices. Consistency in these different market prices can be an indicator of efficient commitment and dispatch of internal and external generating resources.

Overall, system price levels have increased as the state's greenhouse gas allowance program was implemented at the beginning of 2013. Section 3.1 provides further details on the impact of the greenhouse gas program on the ISO market.

Figure 1.1 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively.

- In the first quarter, hour-ahead prices remained lower than day-ahead prices in all months. Hour-ahead prices in the first quarter averaged about $3/MWh lower than day-ahead prices in peak hours and almost $4/MWh lower in off-peak hours.
- Average system prices in the 5-minute real-time market were close to day-ahead prices in peak periods, but about $2/MWh lower during off-peak periods.
- Average system prices in the 5-minute real-time market exceeded hour-ahead prices in most peak and off-peak hours. The largest average difference was over $4/MWh in March during peak hours.

Figure 1.1 Average monthly on-peak prices – system marginal energy price

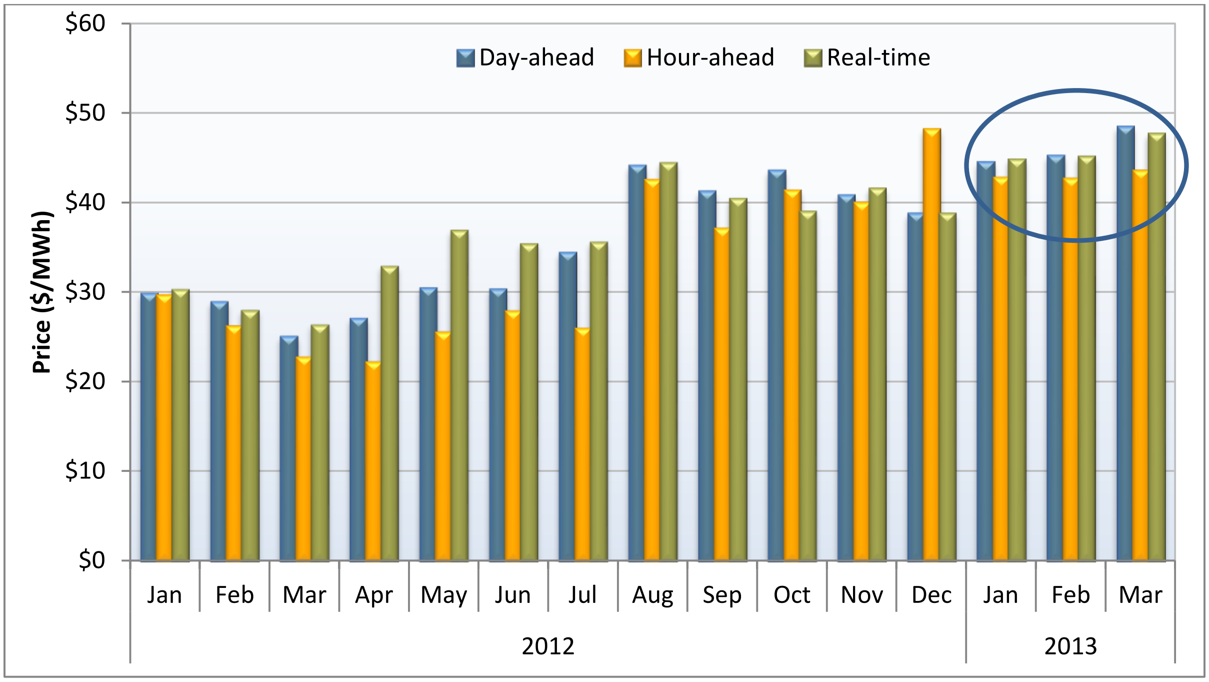


Figure 1.2 Average monthly off-peak – system marginal energy price

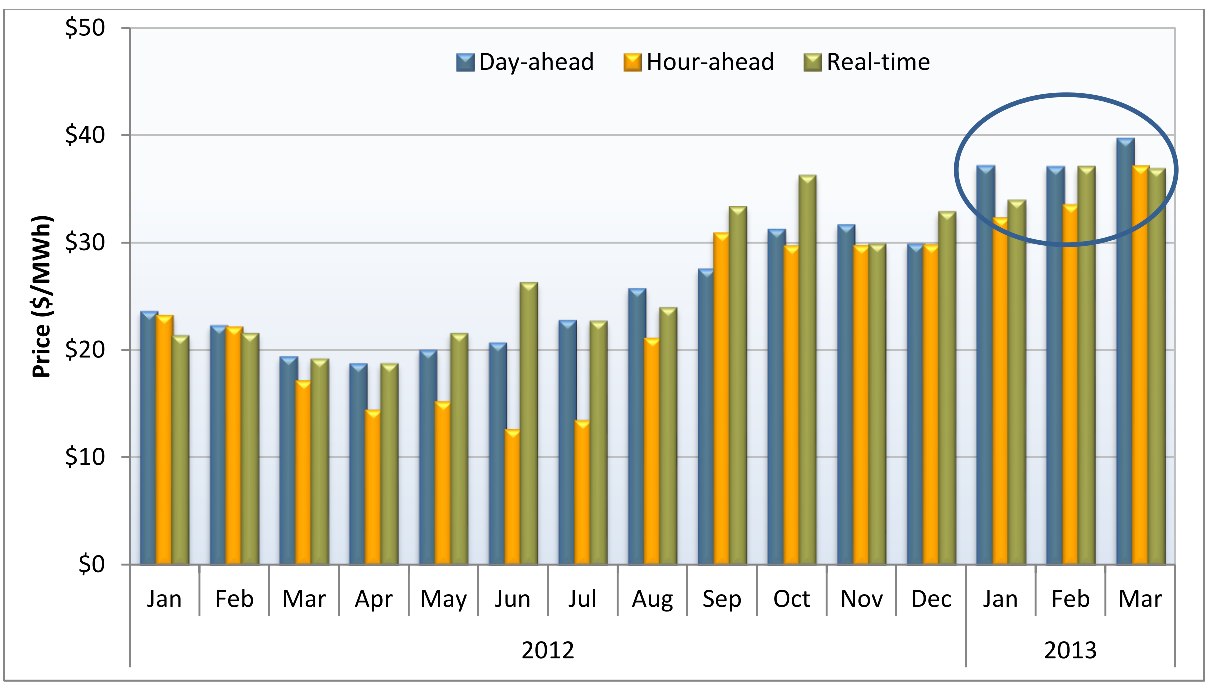


Figure 1.3 shows average hourly prices for the first quarter, which further illustrate that systematic differences between hour-ahead and real-time system prices remained in the first quarter. Real-time prices were higher than hour-ahead prices in 18 of 24 operating hours, averaging almost $4/MWh higher in these hours. In three operating hours, average real-time prices exceeded hour-ahead prices by over $7/MWh.

Hourly average real-time prices tracked much more closely to day-ahead prices during most operating hours. The largest difference between average day-ahead and real-time prices was over $6/MWh in hour ending 14. Hourly average day-ahead prices exceeded hour-ahead prices in 21 hours. The largest differences occurred in the mid-afternoon hours and in the late evening hours.

Figure 1.3 Hourly comparison of system marginal energy prices (January – March)

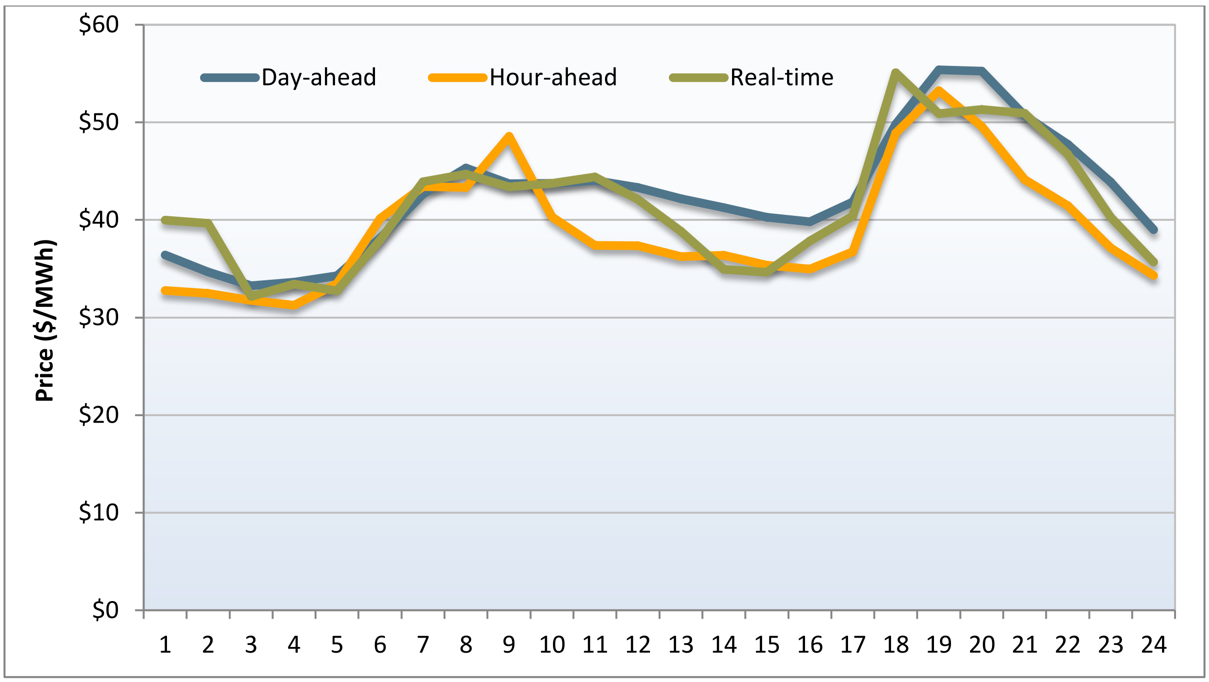
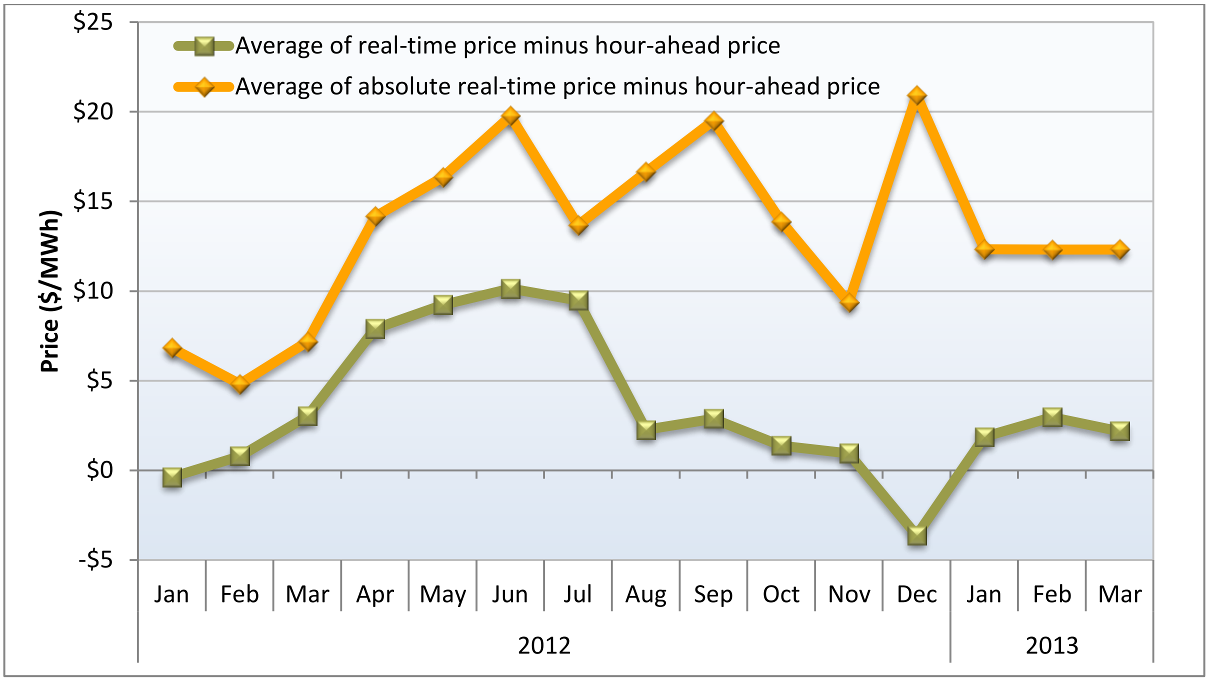


Figure 1.4 highlights the magnitude of price differences for all hours in the hour-ahead and real-time markets based on a simple average of price differences in these markets. Based on the simple average (green line), price divergence was consistently about $2.50/MWh for the quarter.

Also shown in Figure 1.4, the average absolute price difference between the hour-ahead and real-time markets (gold line) shows that price divergence was at about the same level in each month in the first quarter.[6] The average price differences were about $12/MWh, down from $14/MWh in the previous quarter. This consistency between months was a change from previous quarters.

[6] By taking the absolute value, the direction of the difference is eliminated and only the magnitude of the difference remains. Mathematically, this measure will always exceed the simple average of price differences shown in Figure 1.4 if both negative as well as positive price differences occur. If the magnitude decreases, price convergence would be improving. If the magnitude increases, price convergence would be getting worse. DMM does not anticipate that the average absolute price convergence should be zero. This metric is considered secondary to the simple average metrics and helps to further interpret price convergence.

Figure 1.4 Difference in monthly hour-ahead and real-time prices based on simple average and absolute average of price differences (system marginal energy, all hours)



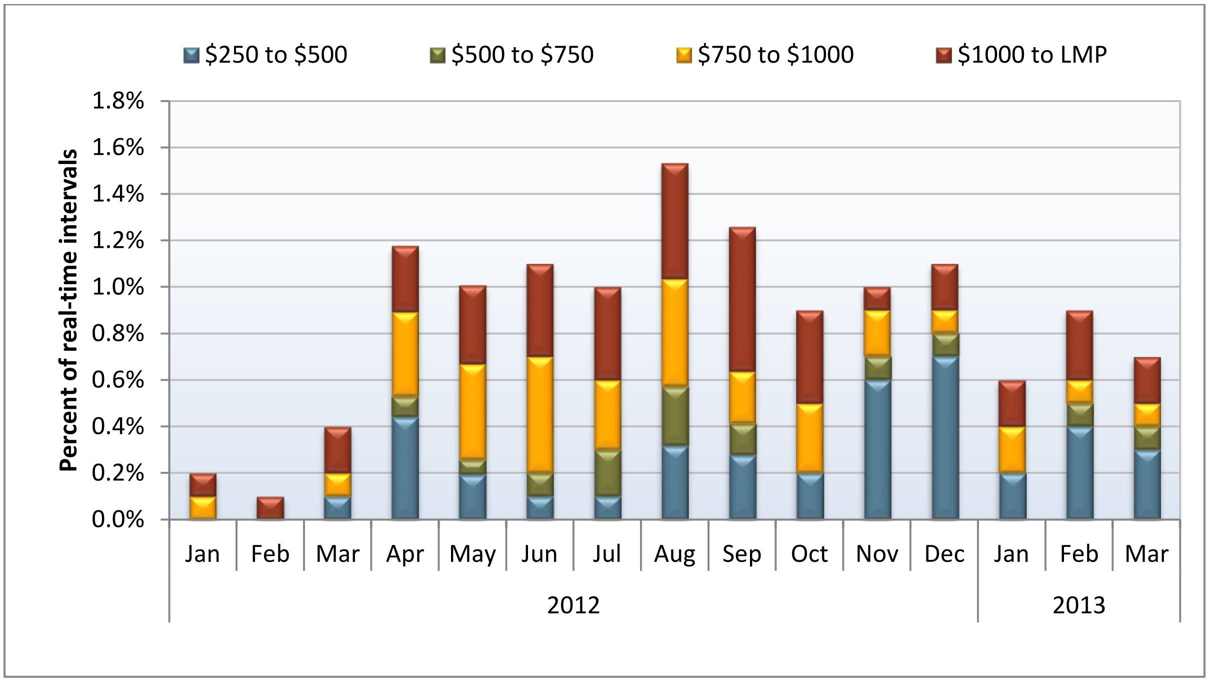
1.2 Real-time price variability

Real-time market prices historically have been very variable, which is highlighted in this section along with reasons why it occurs.

As shown in Figure 1.5, the frequency of price spikes that occur in each load aggregation point in the real-time market decreased slightly, from an average of 1 percent in the fourth quarter to about 0.7 percent in the first quarter. The ISO continued to increase the flexible ramping constraint requirements during the evening ramping hours. The ISO also implemented a new tool in early December 2012 that limits the ability of load adjustments made by the ISO operators to create constraint infeasibilities in the real-time market model. Even with these changes, the market still had many instances of prices approaching or over the bid cap of $1,000/MWh. The underlying reason was that local congestion in the south, especially on the SCE_PCT_IMP branch group, caused price spikes due to upward ramping limitations, mostly in the SCE area. For further detail on congestion, see Section 1.3.

Some of these extremely high prices were caused by system power balance constraint relaxations, which occur when the ISO has limited short-term ramping capacity. Figure 1.6 and Figure 1.7 show the frequency the power balance constraint was relaxed in the 5-minute real-time market since the first quarter of 2012. Figure 1.8 shows factors that contributed to high real-time prices.

Figure 1.5 Frequency of real-time price spikes (all LAP areas)



Power balance constraint relaxations because of insufficient upward ramping capacity were generally higher than the previous quarter, as seen in Figure 1.6. The constraint relaxations were dispersed over different hours of the day but were more common between 6:00 p.m. and 10:00 p.m. during the evening peak ramp period. Limited ramping capacity and congestion contributed to many of the upward ramping limitations.

As in the previous quarter, extreme congestion played a key role in numerous instances of power balance constraint relaxations in the first quarter. Power balance relaxations can also occur in the presence of congestion. In the first quarter, around 60 percent of the upward ramping capacity relaxations shown in Figure 1.6 resulted from extreme regional congestion. Sometimes extreme congestion on constraints within the ISO can limit the availability of significant amounts of supply. This can cause system-wide limitations in upward ramping capacity, and thus cause relaxations in the power balance constraint. In these cases, the cost of relaxing the system power balance constraint is less expensive than the cost of relaxing the internal constraint. Therefore, the system power balance constraint is relaxed to deal with upward ramping limitations in the congested portion of the ISO system.[7]

There was a slight decrease in the number of real-time power balance constraint relaxations from insufficiencies of dispatchable decremental energy in the first quarter relative to the fourth quarter, as shown in Figure 1.7.[8] Outages and low hydro conditions likely contributed to reducing the number of

[7] This is primarily true for large regional constraints. For very small local constraints, the opposite is true. In the case of local constraints, the cost of relaxing the local constraint is less expensive than the cost of relaxing the system power balance constraint. Thus, the local constraint is relaxed instead of the power balance constraint.

[8] When these downward ramping limitations occur, the real-time system energy price is set by a penalty parameter equal to -$35/MWh, just below the bid floor of -$30/MWh.

instances where over-generation occurred in the market compared to previous periods. Almost all of these constraint relaxations resulted from system-wide over-generation conditions.

Figure 1.6 Relaxation of power balance constraint because of insufficient upward ramping capacity

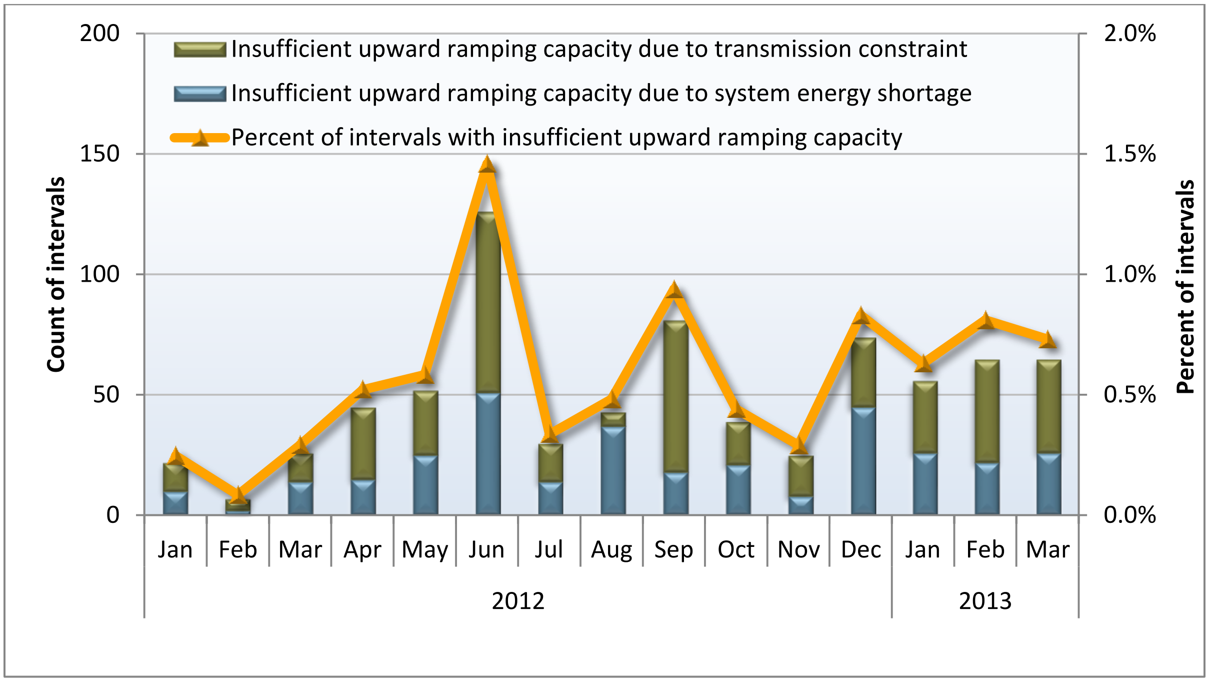


Figure 1.7 Relaxation of power balance constraint because of insufficient downward ramping capacity

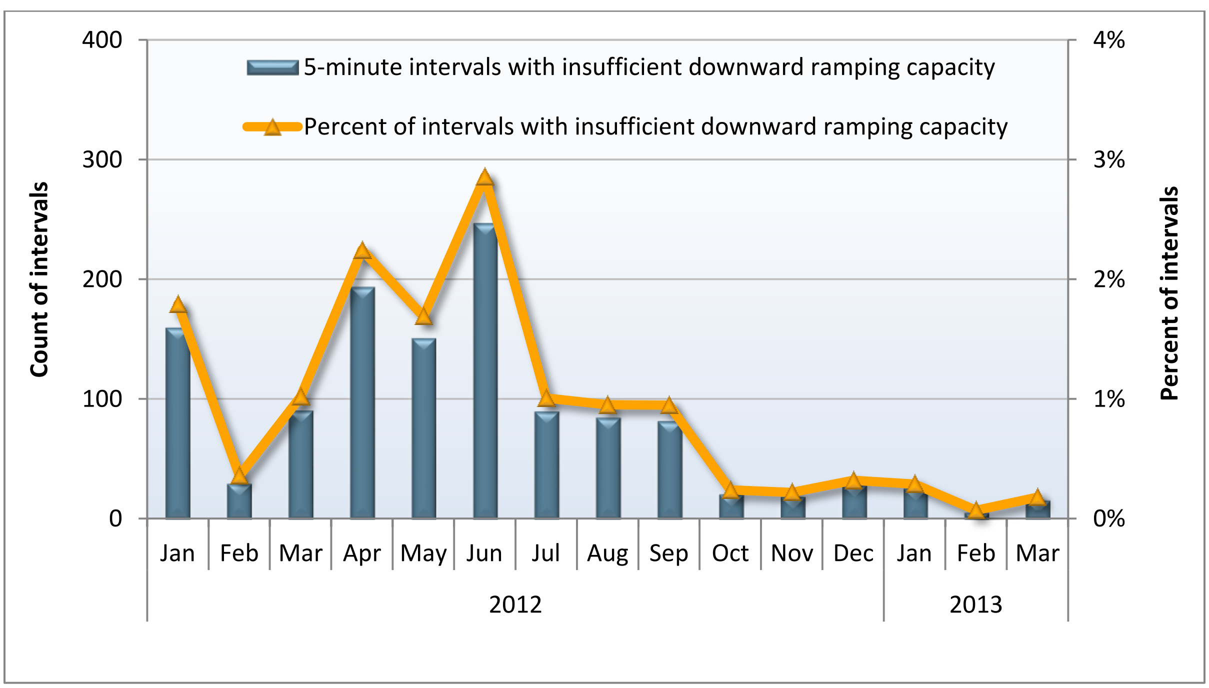
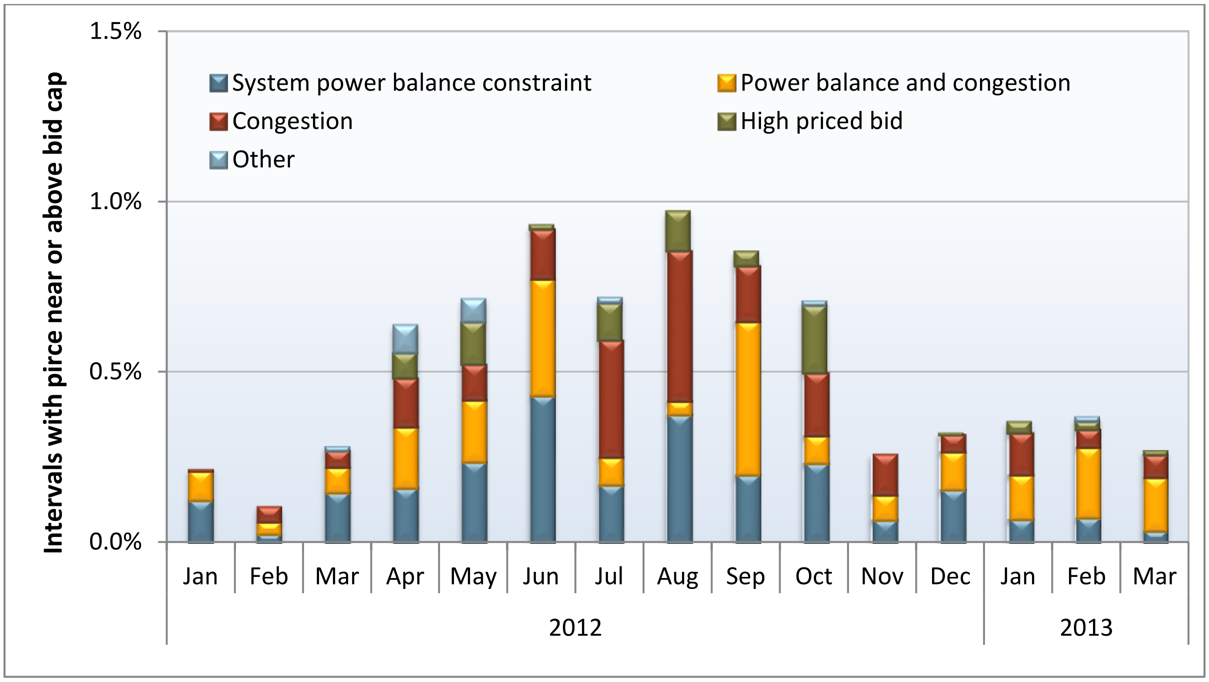


Figure 1.8 Factors causing high real-time prices



Around 75 percent of the extremely high prices were caused by congestion or a combination of power balance constraint relaxations and congestion in the first quarter. About 17 percent were a result of system-wide power balance constraint relaxations by themselves, and 7 percent of the high prices resulted from high priced bids. Figure 1.8 highlights the different factors driving high real-time prices at a regional level. The prices on the figure include all intervals in which the real-time price for a load aggregation point was approaching the bid cap.[9]

1.3 Congestion

Congestion within the ISO system in the first quarter affected overall prices less in the day-ahead and real-time markets than in the fourth quarter. However, congestion, particularly into the Southern California Edison area, continued to have a significant impact on the market. Much of the congestion was related to unscheduled flows on the California-Oregon Intertie (COI), outages of the San Onofre Nuclear Generating Station units 2 and 3, and other generation and transmission outages.

The impact of congestion on any constraint on each pricing node in the ISO system can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as groups of nodes that represent different load aggregation points or local capacity areas.

Often, congestion on constraints in Southern California increases prices within the Southern California Edison and San Diego Gas and Electric areas, but decreases prices in the Pacific Gas and Electric area.

[9] The analysis behind this figure reviews price spikes above $700/MWh.

This is the inverse of congestion in Northern California. The price impacts on individual constraints can also differ between the day-ahead and real-time markets, as seen in the following sections.

1.3.1 Congestion impacts of individual constraints

Day-ahead congestion

Congestion in the day-ahead market generally occurred more frequently, but with a lower impact, than in the real-time market. Table 1.1 provides information related to the frequency and magnitude of day-ahead market congestion.

The most congested constraint in the ISO system was the constraint limiting imports into the SCE area (SCE_PCT_IMP_BG). This constraint was congested in about 71 percent of the hours in the first quarter. When congestion occurred on this constraint, prices in the SCE area increased about $4.85/MWh and decreased in the SDG&E and PG&E areas by about $3.90/MWh. This constraint was directly affected by the SONGS outages.

The SCE area also had the second most congested constraint (BARRE-LEWIS_NG). This constraint increased prices in the SCE and SDG&E areas by $1.84/MWh and $0.21/MWh respectively, while decreasing prices in the PG&E area by $1.32/MWh. This constraint was also directly affected by the SONGS outages.

The San Diego area had the greatest quantity of congested constraints with 11. Many of these constraints were related to outages affecting the Imperial Valley transformers. The 22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80 constraint increased prices in the SDG&E area by $0.28/MWh with negligible impact on the other areas.

In the PG&E area, the most congested constraint was the Path 15 branch group (Path15_BG). This constraint occurred mainly due to forced outages, planned maintenance, intermittent resource deviation and unscheduled flows on the COI. Congestion on this branch group occurred in nearly 8 percent of hours in the south-to-north direction. During these hours, prices in the PG&E area increased by about $1.68/MWh and prices in the SCE and SDG&E areas decreased by about $1.43/MWh.

As shown in Table 1.1, congestion on other constraints significantly affected prices during hours when congestion occurred. However, with the exception of the SCE_PCT_IMP_BG and the BARRE-LEWIS_NG, internal congestion occurred infrequently and typically had a minimal impact on overall day-ahead energy prices.

Table 1.1 Impact of congestion on day-ahead prices during congested hours

Area	Constraint	Frequency	Load area		
			PG&E	SCE	SDG&E
PG&E	PATH15_BG	7.7%	$1.68	-$1.43	-$1.43
SCE	SCE_PCT_IMP_BG	71.2%	-$3.93	$4.85	-$3.89
	BARRE-LEWIS_NG	23.9%	-$1.32	$1.84	$0.21
	PATH26_BG	1.1%	-$1.83	$1.47	$1.47
	SLIC 2088287_BARRE-LEWIS_NG	0.6%	-$1.28	$2.13	
	SOUTHLUGO_RV_BG	0.4%	-$3.24	$2.47	$4.42
SDG&E	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80	6.4%			$0.28
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	3.4%			$4.27
	IVALLYBANK_XFBG	2.6%			$0.84
	SLIC 2051445 TL23050_NG	2.3%			$6.31
	SLIC 2090466 and 2090467 SOL	2.3%			$15.29
	22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1	1.6%			$0.89
	SLIC 2112931 EL CENTRO BK1_NG	1.2%			$5.05
	MIGUEL_BKs_MXFLW_NG	0.4%	-$1.04		$11.65
	24138_SERRANO _500_24137_SERRANO _230_XF_3	0.4%	-$17.48		$41.61
	SLIC 2090865 TL23021_NG	0.4%			$4.72
	SLIC 2094078 IV Bank81_NG	0.2%	-$3.54		$24.91

Real-time congestion

Congestion in the real-time market differs from the day-ahead market in that real-time congestion occurs less frequently overall, but often with a larger price effect in the intervals when it does occur. Table 1.2 shows the frequency and magnitude of congestion in the fourth quarter.

The SCE area was congested by the top two most frequently congested constraints in the first quarter.

- The top constraint, SCE_PCT_IMP_BG, was binding in approximately 10 percent of intervals. This constraint increased prices by about $41/MWh in the SCE area and decreased prices in the PG&E and SDG&E areas by nearly $34/MWh. This constraint was directly affected by the SONGS outages, variable resource output, generation outages and derates.
- With just over 5 percent of the hours congested, the BARRE-LEWIS_NG was the second most congested constraint in the quarter. This constraint alone increased the prices in the SCE area by $5.60/MWh in congested hours, while prices in the PG&E and SDG&E areas decreased by about $8.62/MWh and $6.64/MWh, respectively. This constraint was directly affected by the SONGS outages, intermittent resource output, compensating injections, generation outages and derates.

Prices in the San Diego area were affected by multiple constraints. The IVALLYBANK_XFBG was congested in over 3 percent of the intervals, increasing prices by $2.25/MWh in SDG&E and with negligible impact on the SCE and PG&E areas. Occurring in only 0.5 percent of the intervals, the 7830_TL_230S_IV-SX-OUT_NG had a $51.47/MWh impact on the SDG&E area prices and a negligible price impact in the other areas.

Pacific Gas and Electric area prices were most influenced by south-to-north congestion on Path 15 (2.1 percent). The Path15_S-N constraint increased prices in the PG&E area by about $52/MWh and decreased both the SCE and SDG&E area prices by nearly $44/MWh. Congestion on the Path15_S-N constraint was influenced by Midway-Gates 500 kV line maintenance, compensating injections, intermittent resources and flows on COI.

Table 1.2 Impact of congestion on real-time prices during congested intervals

Area	Constraint	Frequency	Load area		
			PG&E	SCE	SDG&E
PG&E	PATH15_S-N	2.1%	$52.05	-$43.98	-$43.98
	T-135 VICTVLUGO_PVDV_NG	0.1%	$33.40	-$38.73	
	SLIC 2094628 PATH 15 S-N MIN	0.004%	$496.15	-$417.76	-$417.76
SCE	SCE_PCT_IMP_BG	10.0%	-$33.78	$41.04	-$33.48
	BARRE-LEWIS_NG	5.4%	-$8.62	$5.60	-$6.64
	PATH26_N-S	2.0%	-$23.96	$19.63	$19.63
	PATH15_N-S	0.0%	-$56.37	$47.06	$47.06
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	0.0%	-$320.31	$267.35	$267.35
SDG&E	IVALLYBANK_XFBG	3.1%			$2.55
	7830_TL 230S_IV-SX-OUT_NG	0.5%			$51.47
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	0.4%	-$2.22	-$5.25	$15.46
	7820_TL 230S_OVERLOAD_NG	0.4%			$29.90
	SLIC 2090466 and 2090467 SOL	0.3%			$30.74
	SLIC 2051445 TL23050_NG	0.2%			$46.55
	SLIC 2112931 EL CENTRO BK1_NG	0.2%			$49.40
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	0.2%			$12.56
	24138_SERRANO _500_24137_SERRANO _230_XF_3	0.1%	-$32.00		$80.19
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.1%	-$37.04		$92.29

Overall, congestion is more frequent in the day-ahead market compared to the real-time market when comparing Table 1.1 and Table 1.2. However, the price impact of congestion is often lower in the day-ahead market than the real-time market. Differences in congestion in the day-ahead and real-time markets occur as system conditions change, as virtual bids liquidate, and as constraints are sometimes adjusted in real-time to make market flows consistent with actual flows and to provide a reliability margin.

For instance, the SCE_PCT_IMP_BG was binding in roughly 71 percent of the hours in the day-ahead market compared to about 10 percent of intervals in the real-time market. While this constraint increased day-ahead prices in the SCE area by nearly $5/MWh, it increased prices by over $41/MWh in the real-time market. A similar pattern can be seen with the BARRE-LEWIS_NG constraint.

1.3.2 Congestion impact on average prices

This section provides an assessment of differences on overall average prices in the day-ahead and real-time markets caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is made based on the average congestion component of the price as a percent of the total price during all congested and non-congested hours. This approach shows the impact of congestion taking into account the frequency that congestion occurs as well as the magnitude of the impact that congestion has when it occurs.[10]

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load area in the first quarter by constraint.

The SCE_PCT_IMP_BG increased day-ahead prices in the SCE area above system average prices by $3.45/MWh or almost 7.5 percent, up from $1.48/MWh (4 percent) in the fourth quarter. Prices decreased by about $2.78/MWh (7 percent) in the PG&E and SDG&E areas. This constraint is designed to ensure that enough generation is supplied from units within the SCE area in the event of a contingency that significantly limits imports into SCE or decreases generation within the SCE area. The BARRE-LEWIS_NG increased the prices in the SCE area by $0.44/MWh or 1 percent and decreased PG&E area prices by $0.31/MWh or 0.8 percent with a very small price impact on SDG&E area prices.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$2.80	-7.03%	$3.45	7.49%	-$2.77	-6.73%
BARRE-LEWIS_NG	-$0.31	-0.79%	$0.44	0.95%	$0.01	0.02%
PATH15_BG	$0.13	0.33%	-$0.11	-0.24%	-$0.11	-0.27%
SLIC 2090466 and 2090467 SOL					$0.35	0.84%
24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.07	-0.16%			$0.15	0.37%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					$0.15	0.36%
SLIC 2051445 TL23050_NG					$0.15	0.35%
SLIC 2094078 IV Bank81_NG	-$0.01	-0.02%			$0.06	0.14%
SLIC 2112931 EL CENTRO BK1_NG					$0.06	0.15%
MIGUEL_BKs_MXFLW_NG	$0.00	-0.01%			$0.05	0.12%
PATH26_BG	-$0.02	-0.05%	$0.02	0.03%	$0.02	0.04%
SOUTHLUGO_RV_BG	-$0.01	-0.03%	$0.01	0.02%	$0.02	0.04%
IVALLYBANK_XFBG					$0.02	0.05%
SLIC 2088287_BARRE-LEWIS_NG	-$0.01	-0.02%	$0.01	0.03%		
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80					$0.02	0.04%
SLIC 2090865 TL23021_NG					$0.02	0.04%
22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1					$0.01	0.04%
Other	$0.14	0.36%	$0.05	0.11%	$0.05	0.11%
Total	-$2.95	-7.4%	$3.87	8.4%	-$1.77	-4.3%

The day-ahead prices in the SDG&E area were impacted by the SCE constraints mentioned above. Additionally, the constraint SLIC 2090466 and 2090467 SOL increased prices by $0.35/MWh or around 0.8 percent. This was associated with a planned outage on the Imperial Valley-Ocotillo and Ocotillo-Suncrest 500 kV lines.

The overall impact of congestion on day-ahead prices in the PG&E area decreased prices by about $2.95/MWh or about 7.4 percent from the system average. This occurred because prices in the PG&E

[10] In addition, this approach identifies price differences caused by congestion without including price differences that result from variations in transmission losses at different locations.

area were lower when congestion occurred on the constraints limiting flows into the SCE and SDG&E areas.

Real-time price impacts

Table 1.4 shows the overall impact of real-time congestion on average prices in each load area in the first quarter by constraint.

Congestion drove prices in the SCE area above system average prices by about $4.42/MWh or almost 10 percent. Most of this increase was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area (SCE_PCT_IMP_BG). Another major driver of congestion was constraints on the south-to-north congestion on Path 15, which decreased prices in the SCE area by nearly $1/MWh (2 percent).

Prices in the San Diego area were impacted the most by congestion associated with the SCE_PCT_IMP_BG, PATH15_S-N and PATH26_N-S constraints. The SCE_PCT_IMP_BG and PATH26_N-S constraints drove SDG&E prices down while PATH26_N-S drove prices up. Combined, these three constraints drove San Diego area prices below the system average by nearly 10 percent or about $3.90/MWh.

The overall impact of congestion on prices in the PG&E area was to decrease prices from the system average by about $3.39/MWh or about 9 percent. Prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows in the north-to-south direction (e.g., PATH26_N-S) and on constraints limiting flows into the SCE (e.g., SCE_PCT_IMP_BG) and SDG&E areas. Congestion on the Path15_S-N constraint was influenced by Midway-Gates 500 kV line maintenance, compensating injections, intermittent resources and flows on COI. This constraint increased prices over $1/MWh (2.9 percent) during the first quarter in the PG&E area.

Overall, real-time congestion occurred less frequently than day-ahead congestion, yet its effect on overall price levels was larger than what occurred in the day-ahead market. As mentioned earlier, the differences in congestion can be attributed to differences in market conditions as well as changes associated with conforming line limits to make market flows reflect actual flows and to provide a reliability margin.

Table 1.4 Impact of congestion on overall real-time prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$3.39	-8.89%	$4.12	9.02%	-$3.36	-8.72%
PATH15_S-N	$1.09	2.86%	-$0.92	-2.02%	-$0.92	-2.40%
PATH26_N-S	-$0.48	-1.25%	$0.39	0.86%	$0.39	1.02%
BARRE-LEWIS_NG	-$0.47	-1.23%	$0.30	0.66%	-$0.02	-0.04%
SCIT_BG	-$0.11	-0.29%	$0.09	0.20%	$0.10	0.26%
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	-$0.11	-0.29%	$0.09	0.20%	$0.09	0.24%
7830_TL 230S_IV-SX-OUT_NG					$0.25	0.66%
7820_TL 230S_OVERLOAD_NG					$0.11	0.28%
24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.03	-0.08%			$0.07	0.19%
SLIC 2051445 TL23050_NG					$0.10	0.25%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.03	-0.07%			$0.07	0.18%
SLIC 2112931 EL CENTRO BK1_NG					$0.09	0.24%
SLIC 2090466 and 2090467 SOL					$0.09	0.24%
IVALLYBANK_XFBG					$0.08	0.20%
22464_MIGUEL _230_22468_MIGUEL _500_XF_81	-$0.01	-0.02%	$0.00	-0.01%	$0.07	0.17%
T-135 VICTVLUGO_PVDV_NG	$0.02	0.06%	-$0.03	-0.06%		
SLIC 2094628 PATH 15 S-N MIN	$0.02	0.05%	-$0.02	-0.04%	-$0.02	-0.04%
PATH15_N-S	-$0.02	-0.04%	$0.01	0.03%	$0.01	0.03%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					$0.02	0.05%
Other	$0.12	0.31%	$0.38	0.83%	-$0.27	-0.70%
Total	-$3.39	-8.9%	$4.42	9.7%	-$3.04	-7.9%

Congestion price difference between the day-ahead, hour-ahead and real-time markets

This section compares the congestion price differences between the day-ahead, hour-ahead and real-time markets as a simple and absolute average over time. In terms of both the simple and absolute averages, congestion differences have reduced somewhat between the markets in the first quarter of 2013 compared to the last half of 2012.

Figure 1.9 shows the monthly average and absolute congestion price differences between the day-ahead and real-time markets since January 2011 for each load area. Figure 1.10 shows the monthly average and absolute congestion price difference between the day-ahead and hour-ahead markets by load area for the same period.

With the exception of SDG&E congestion in early 2011, which had short periods of congestion differences, the simple average (dashed line) and absolute average (solid line) price divergence between the day-ahead and the other markets was relatively small in 2011. This trend continued into the first part of 2012. Beginning in February 2012, however, and continuing through the rest of the year, day-ahead market congestion differed significantly from both real-time and hour-ahead congestion with the simple average and even more so with the absolute average. The difference in the first quarter of 2013 is the San Diego area congestion has, in absolute terms, moved in line with the other areas. This is primarily due to the nature of the congestion in the first quarter, which was mostly impacted by the SCE_PCT_IMP_BG constraint and less so by specific San Diego constraints.

Figure 1.9 Monthly average and absolute congestion price differences between the day-ahead and real-time markets

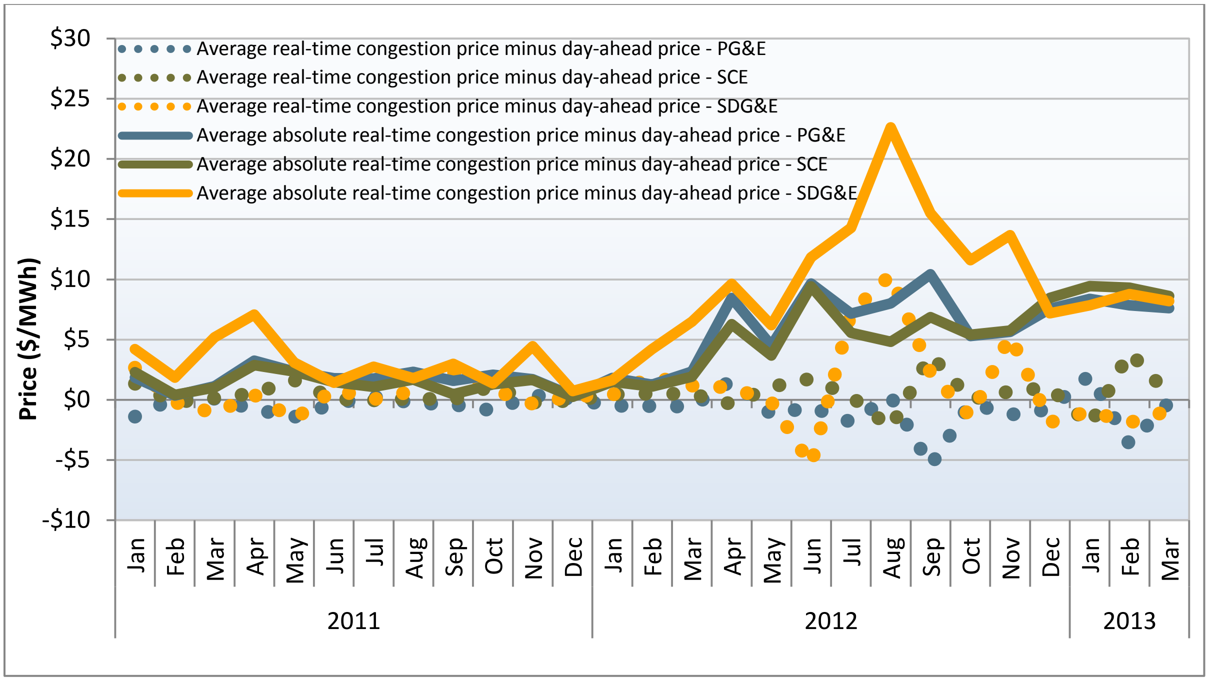
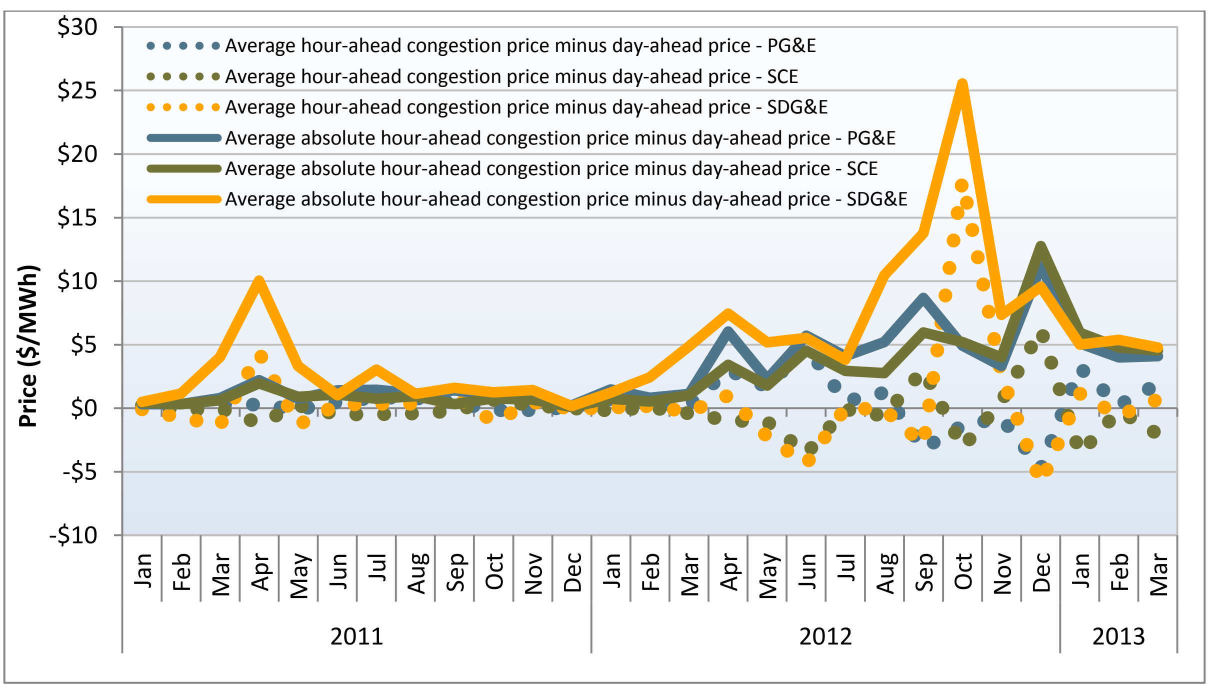


Figure 1.10 Monthly average and absolute congestion price differences between the day-ahead and hour-ahead markets



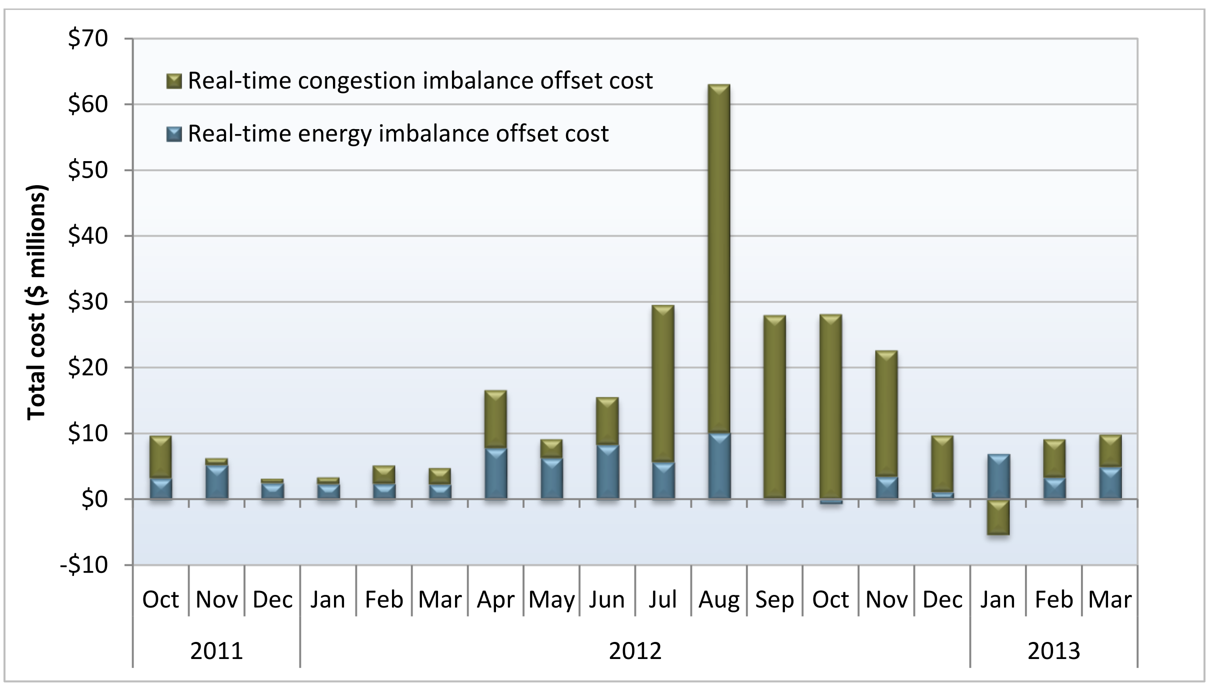
In March 2013, for example, the absolute difference in load area prices between the day-ahead market and the real-time market was around $8/MWh while the average difference was approximately $0/MWh. Day-ahead and hour-ahead market price differences between the load areas improved in absolute terms but were different than simple average prices. In March 2013, these load area price differences for all three areas averaged about $5/MWh and $0/MWh for absolute and simple averages, respectively.

1.4 Real-time imbalance offset costs

Real-time imbalance offset costs totaled about $21 million in the first quarter, a relatively low value historically. Congestion offset costs were substantially lower than prior quarters (see Figure 1.11), totaling over $5 million in the first quarter. Energy imbalance offset costs were just over $15 million in the first quarter, a value relatively consistent with previous periods. In part, the ISO's efforts to address systematic modeling differences between the day-ahead and real-time markets contributed to reducing real-time imbalance costs this quarter. Even so, the possibility of high real-time imbalance offset costs continues to exist.

Of note, the negative congestion offset value for January 2013 (about -$5 million) was driven by congestion offset costs on a single day, January 13.

Figure 1.11 Real-time imbalance offset costs



1.5 Exceptional dispatch

Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an *out-of-market* dispatch. While exceptional dispatches are necessary for reliability, they create uplift costs not fully recovered through market prices, can affect market prices and create opportunities for the exercise of temporal market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitments** — Exceptional dispatches can be used to instruct a generating unit to start-up or continue operating at their minimum operating levels. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.
- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would likely have cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as *in-sequence* real-time energy.
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in *out-of-sequence* real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to local market power mitigation provisions of the ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

Decrease in total energy from exceptional dispatch

Total energy, including commitments, resulting from all the types of exceptional dispatches described above decreased in the first quarter by about 45 percent year-over-year from 2012, as shown in Figure 1.12.[11] Total energy from exceptional dispatches, including minimum load energy from unit commitments, equaled 0.19 percent of system loads in the first quarter of 2013, compared to 0.35 percent in the first quarter of 2012. Total energy from exceptional dispatches remains a relatively low portion of total system loads.

Minimum load energy from units committed through exceptional dispatch fell roughly 5 percent from 2012 and accounted for over 80 percent of all energy from exceptional dispatches in the first quarter. As shown in Figure 1.13, much of the minimum load energy was from unit commitments related to general system capacity requirements (nearly 60 percent).

Energy from real-time incremental exceptional dispatches decreased in the first quarter by about 80 percent year-over-year and accounted for nearly 20 percent of total exceptional dispatch energy. Most of this exceptional dispatch energy (about 75 percent) was out-of-sequence, meaning the generator's bid was greater than the price at the generator's location.

[11] All exceptional dispatch data are estimates derived from SLIC logs, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined from methods used in reports prior to the DMM's *2012 Annual Report on Market Issues and Performance* available at http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

Figure 1.14 shows that this decrease in out-of-sequence energy was driven primarily by the decrease in exceptional dispatches made to position resources for ramping purposes to meet contingencies related to the Southern California Import Transmission (SCIT) constraint.

Figure 1.12 Average hourly energy from exceptional dispatch

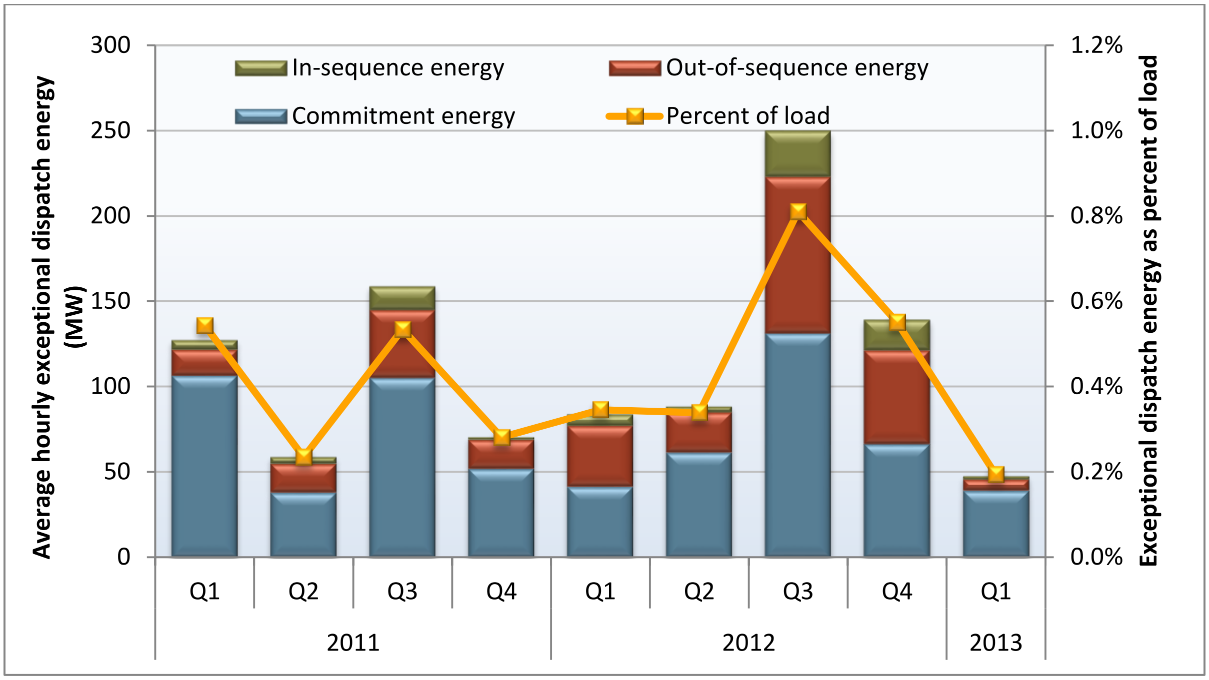


Figure 1.13 Average minimum load energy from exceptional dispatch unit commitments

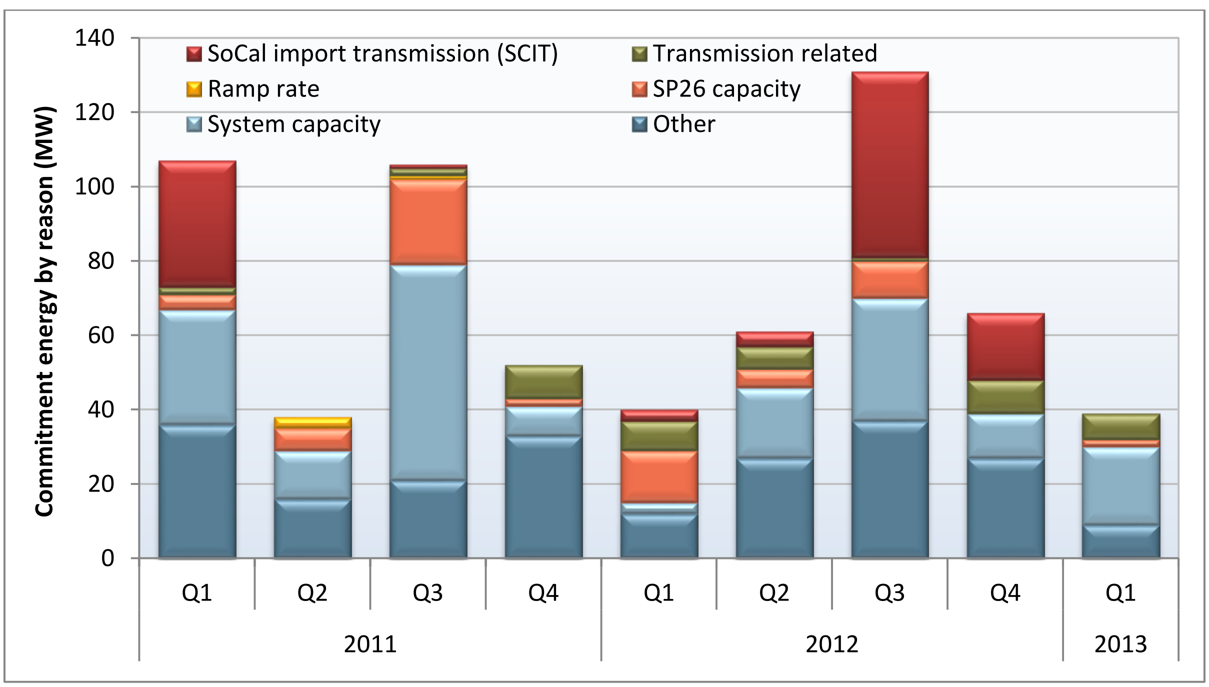
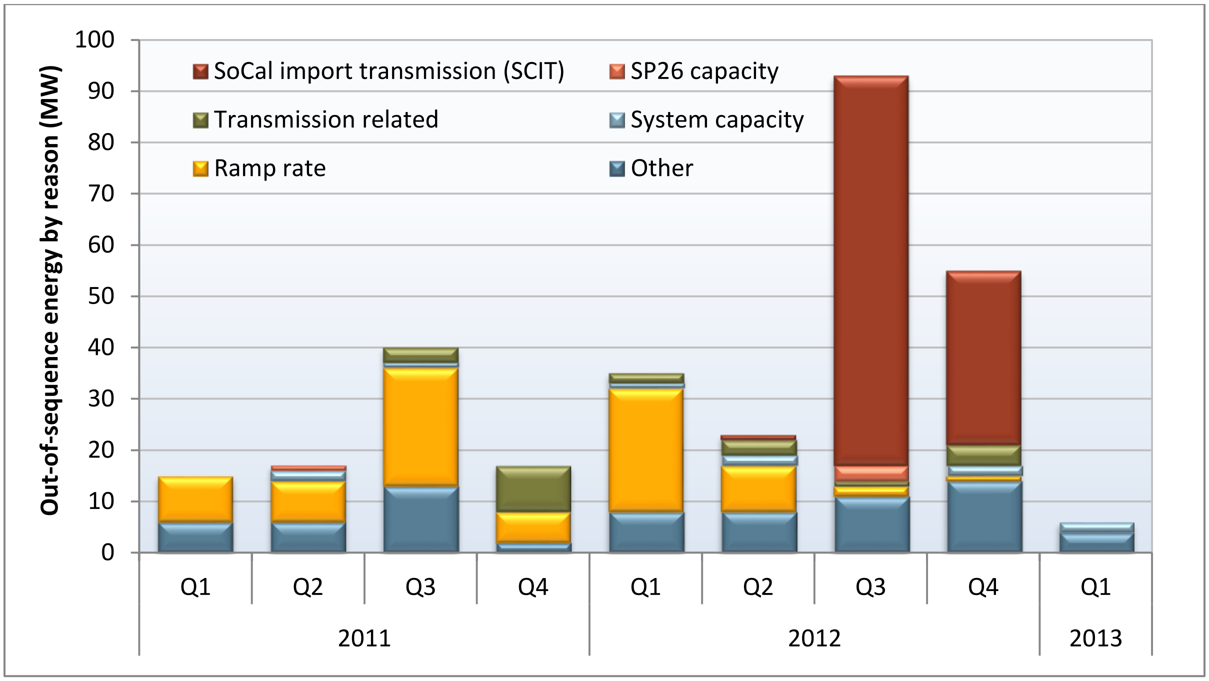


Figure 1.14 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

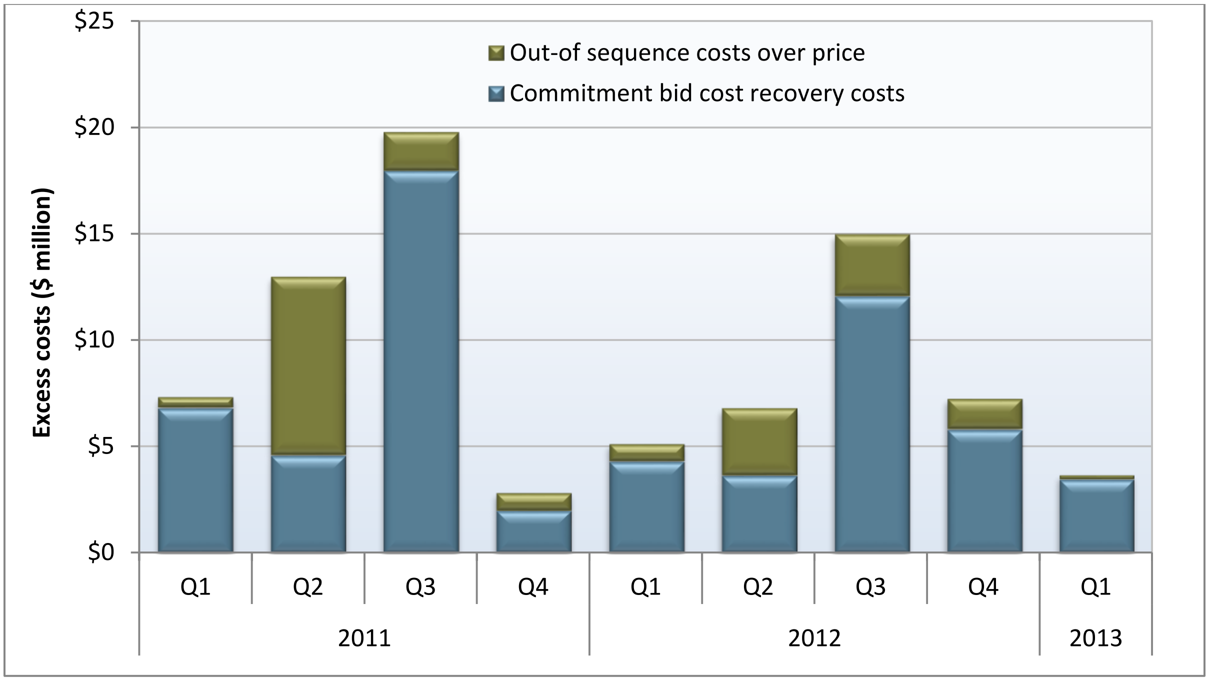
- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for any such costs.
- Units being exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

Figure 1.15 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. Overall, above-market costs decreased about 29 percent from $5.1 million in the first quarter of 2012 to $3.6 million in the first quarter of 2013. Commitment costs paid through bid cost recovery decreased from about $4.3 million to almost $3.5 million during this period, while out-of-sequence energy costs decreased from just over $800,000 to below $200,000 for the same period.[12] This decrease in costs was primarily driven by lower

[12] The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

bid cost recovery payments attributable to commitment exceptional dispatches and the decrease in real-time incremental exceptional dispatches.

Figure 1.15 Excess exceptional dispatch cost by type



1.6 Residual unit commitment

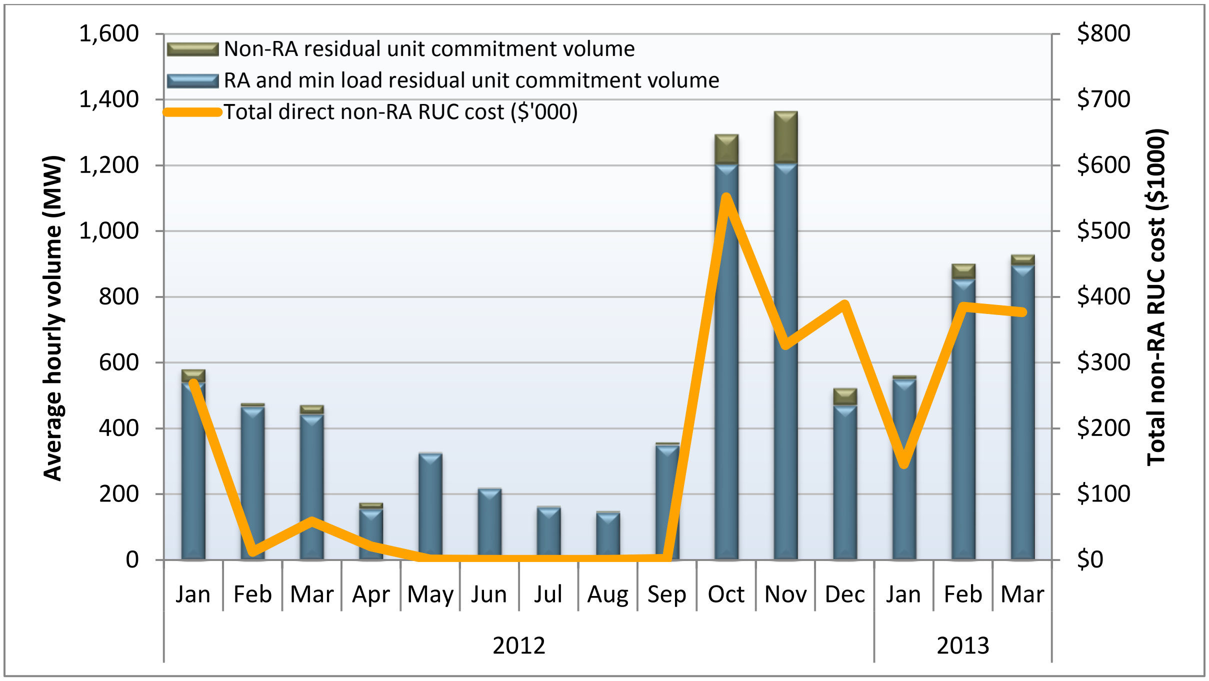
The direct costs of procuring residual unit commitment capacity remained high in the first quarter at almost $1 million compared to total direct costs of about $2 million for all of 2012.[13] Increased residual unit commitment costs have primarily been driven by an increase in residual unit commitment requirements.

Much of this capacity does not incur direct costs but does account for a portion of the bid cost recovery payments discussed in further detail below. Figure 1.16 illustrates average hourly direct non-resource adequacy costs by month in addition to the average hourly residual unit commitment procurement, categorized as either non-resource adequacy or resource adequacy and minimum load.

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet forecast load in real time. The residual unit commitment market is run right after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load that cleared in the day-ahead market and the day-ahead forecast load. ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes and have used this tool frequently in the first quarter.

[13] The direct costs are the megawatts associated with non-resource adequacy capacity committed by the residual unit commitment multiplied by the awarded price for the unit's location in the residual unit commitment market.

Figure 1.16 Residual unit commitment costs and volume



The increase in the residual unit commitment requirement made by operators during the first quarter was related to the decreased reliance on exceptional dispatch, which increased the use of alternative means of ensuring adequate capacity and ramping in real time.

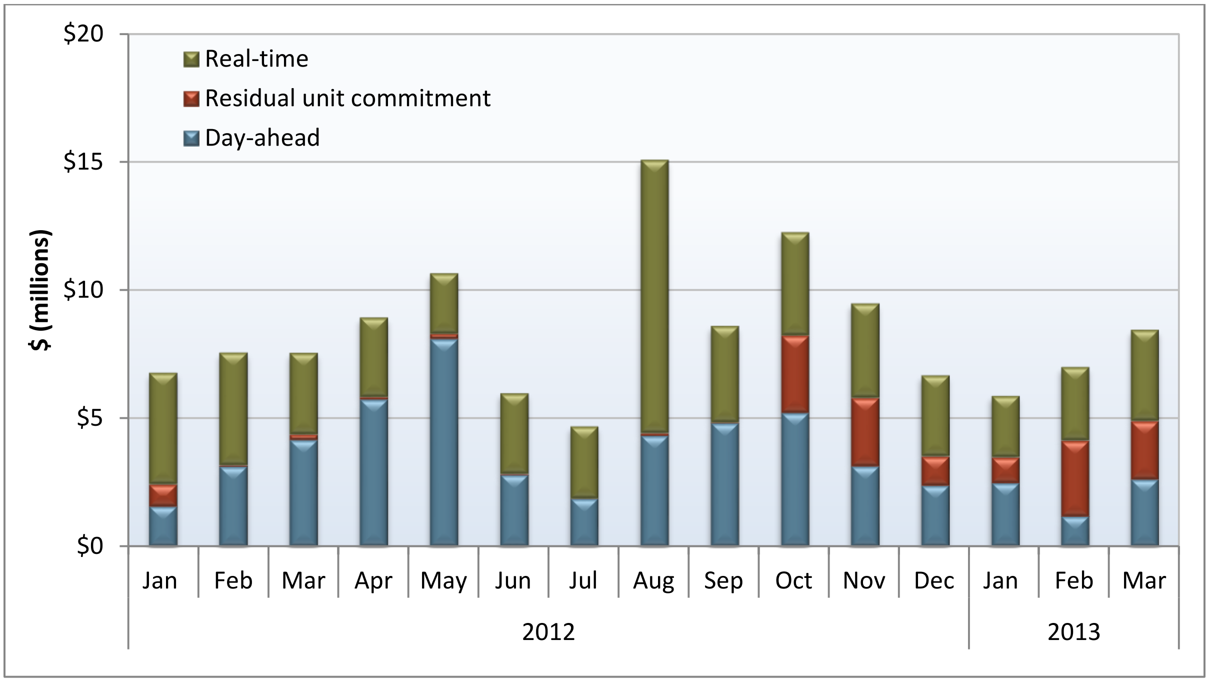
1.7 Bid cost recovery payments

Bid cost recovery payments are designed to ensure that generators receive enough market revenues to cover the cost of all their bids when dispatched by the ISO.[14] Bid cost recovery payments totaled around $21 million in the first quarter, compared to $28 million in the fourth quarter (see Figure 1.13). Bid cost recovery payments resulting from residual unit commitments were above $6 million in the first quarter, which was consistent with the fourth quarter but substantially higher than during prior periods of 2012.

As noted above, the ISO continues its efforts to decrease the amount of exceptionally dispatched energy in real time. Specifically, these increases in requirements were to address load and generation uncertainty. As a result, ISO operators increased system or regional residual unit commitment requirements to mitigate potential contingencies. These increases were concentrated in the late afternoon and early evening hours during the steep ramping period in real time. While these units were committed in the residual unit commitment process to meet these system needs, they were frequently uneconomic in real time, requiring recovery of their start-up and minimum load bid costs.

[14] Bid cost recovery covers the bids for start-up, minimum load, ancillary services, residual unit commitment availability, and day-ahead and real-time energy.

Figure 1.17 Monthly bid cost recovery payments



2 Convergence bidding

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all other ISOs with day-ahead energy markets. In the California ISO markets, virtual bidding is formally referred to as *convergence bidding*. The ISO implemented convergence bidding in the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was temporarily suspended on November 28, 2011.[15] On May 2, 2013, FERC issued an order conditionally accepting elimination of the convergence bidding on inter-ties.[16]

When convergence bids are profitable, they may increase market efficiency by improving day-ahead unit commitment and scheduling. Convergence bidding also provides a mechanism for participants to hedge or speculate against price differences in the two following circumstances:

- price differences between the day-ahead and real-time markets; and
- congestion at different locations.

The first quarter of 2013 marks the first quarter that participants engaged in convergence bidding paid more money into the ISO markets than what they received from their convergence bids. Total net revenues for the entities engaging in convergence bidding during this period were around negative $3 million. Most of these negative revenues resulted from offsetting virtual demand and supply bids at different internal locations designed in an attempt to profit from higher anticipated congestion between these locations in real-time. This type of offsetting internal bids represented over 73 percent of all accepted virtual bids in the first quarter, up from 62 percent in the previous quarter.

Internal virtual supply averaged around 1,600 MW while virtual demand averaged around 1,825 MW during each hour of the quarter. Thus, the average hourly net virtual position in the first quarter was 225 MW of virtual demand, down from 350 MW in the fourth quarter. Net virtual demand within the ISO may help to increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling, and reducing real-time prices. For the quarter, the net revenues for the net virtual demand positions were negative.

Background

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similar to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the hour-ahead and real-time markets, which are dispatched based only on physical supply and demand. Virtual bids accepted in the day-ahead market are liquidated financially in the real-time market as follows:

[15] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. More information can also be found under FERC docket number ER11-4580-000.

[16] See 143 FERC ¶ 61,157 (2013) conditionally accepting elimination of inter-tie convergence bidding. In the order, FERC indicates that the ISO should address within a year the issue of structural separation between hour-ahead and real-time market prices or explain why it has not done so before it reevaluates the efficiency of convergence bidding on inter-ties.

- Participants with virtual demand bids accepted in the day-ahead market pay the day-ahead price for this virtual demand. Virtual demand at points within the ISO is then paid the real-time price for these bids.

- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. Virtual supply at points within the ISO is then charged the real-time price.

Thus, virtual bidding allows participants to profit from any difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should tend to make prices in these different markets closer as illustrated by the following:

- If prices in the real-time market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to the commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.

- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[17] This would tend to increase average real-time prices. In this scenario, virtual supply could help improve price convergence by reducing day-ahead prices and increasing real-time prices.

However, the degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been assessed.

2.1 Convergence bidding trends

Total hourly trading volumes increased to 3,425 MW in the first quarter from 3,300 MW in the fourth quarter. Also, the share of cleared virtual demand dropped to 53 percent in the first quarter down from 59 percent in the previous quarter.

Figure 2.1 shows the monthly quantities of virtual demand and supply offered and cleared in the market. Figure 2.2 illustrates an hourly distribution of the offered and cleared volumes over the fourth quarter. As shown in these figures:

- On average, 53 percent of virtual supply and demand bids offered into the market cleared in the first quarter.

- Cleared volumes of virtual demand outweighed cleared virtual supply in the first quarter by around 225 MW on average, down from around 350 MW in the previous quarter.

[17] This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-solves the market to the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

Figure 2.1 Monthly average virtual bids offered and cleared

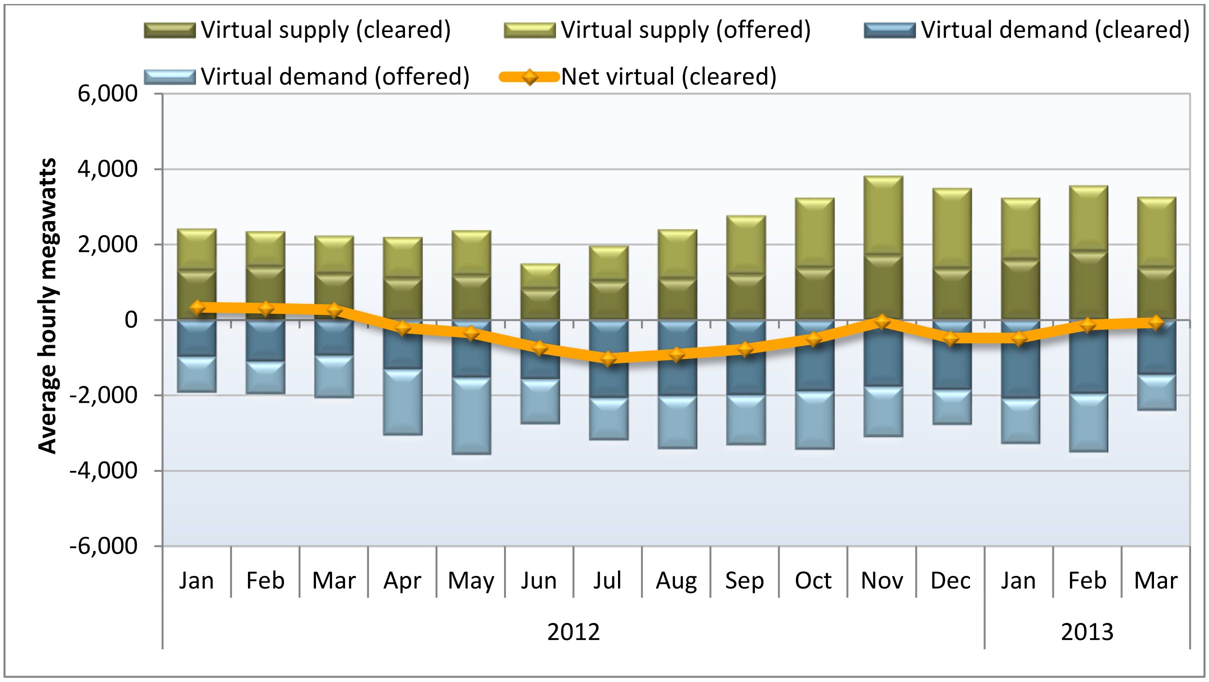
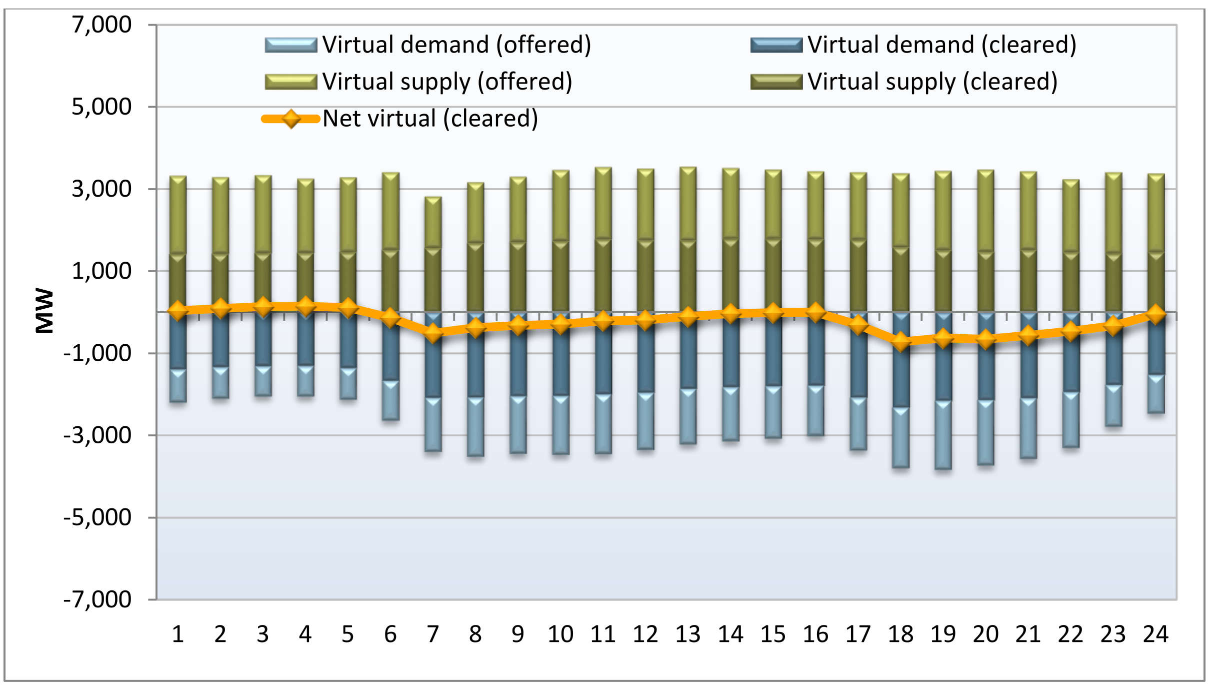


Figure 2.2 Hourly offered and cleared virtual activity (January – March)



- Virtual demand exceeded virtual supply during peak hours by about 340 MW, while during the off-peak hours virtual supply and virtual demand were approximately the same. In the previous quarter, the same trend existed in the off-peak hours, but in the peak periods the virtual demand volumes were higher.

Consistency of price differences and volumes

Convergence bidding is designed to bring together day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. Net convergence bidding volumes were consistent with price differences in about half of the hours in the second half of 2012. However, in the first quarter of 2013, net convergence bidding volumes were not consistent with price differences between the day-ahead and real-time markets in most hours.

Figure 2.3 compares cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different internal locations.

When the red line is positive, it indicates that the weighted average price charged for internal virtual demand in the day-ahead market was higher than the weighted average real-time price paid for this virtual demand. Thus, when positive, it indicates that a virtual demand strategy was not profitable and thus was directionally inconsistent with weighted average price differences.

In the first quarter, overall virtual demand volumes were not consistent with weighted average price difference for the hours in which virtual demand cleared the market in each month. In 2012, virtual demand was consistent with price differences in three-quarters of the months.

During months when the yellow line is positive, this indicates that the weighted average price paid for internal virtual supply in the day-ahead market was higher than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. On average, virtual supply positions at internal locations have been consistently profitable since July 2012.

As noted earlier, a large portion of the internal virtual supply clearing the market was paired with internal demand bids at different internal locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or speculating from internal congestion within the ISO. When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable due to congestion.

Figure 2.3 Convergence bidding volumes and weighted price differences at internal locations

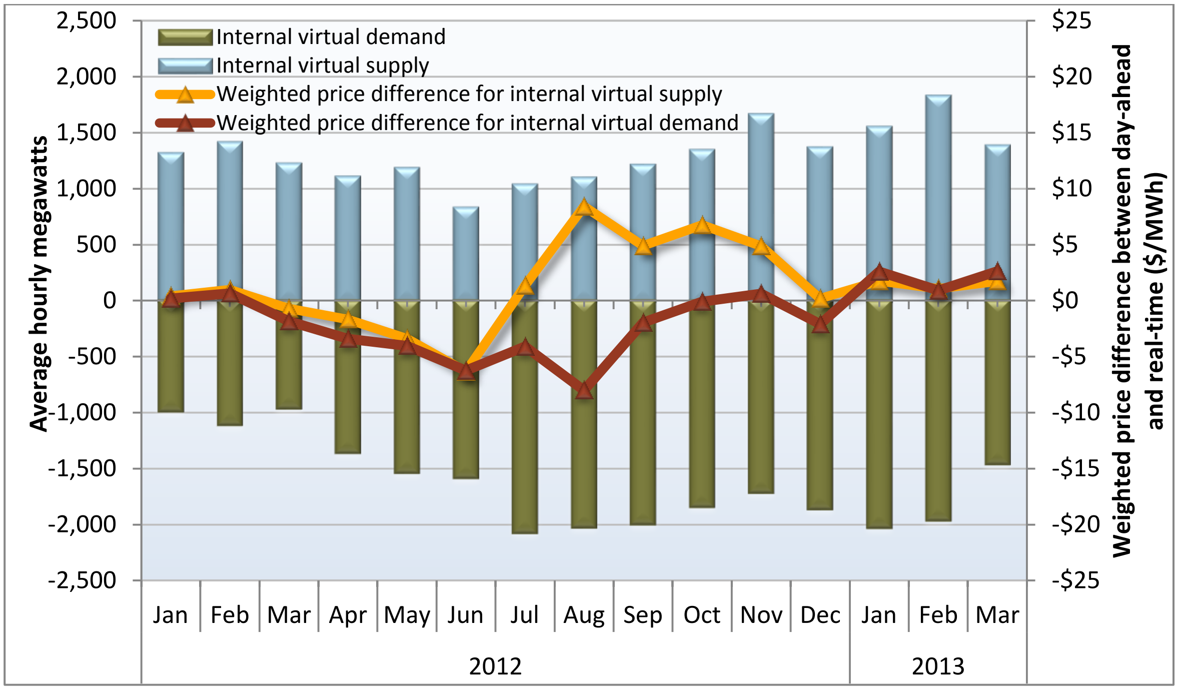


Figure 2.4, Figure 2.5 and Figure 2.6 show average hourly net cleared convergence bidding volumes compared to the difference in the day-ahead and real-time system marginal energy prices in January, February and March, respectively. The blue bars represent the net cleared internal virtual position, whereas the green line represents the difference between the day-ahead and real-time system marginal energy prices. In anticipation of real-time price spikes, market participants often bid virtual demand in peak hours. Even though these spikes do not occur often, the revenues frequently outweigh losses that happened otherwise. However, the results in the first quarter were an exception compared to previous periods (see Section 2.2 for further detail).

- As shown in Figure 2.4, convergence bidding volumes in January were not consistent with price differences in most hours. In total, there were only 9 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences.
- In February, as seen in Figure 2.5, convergence bidding volumes were also not directionally consistent with differences between day-ahead and real-time prices in most hours. The magnitude of the net virtual demand decreased significantly as compared to the previous month. Again, only 9 hours were directionally consistent with day-ahead and real-time differences.
- Figure 2.6 illustrates improved consistency in most hours for net virtual positions in March. In total, there were 14 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences.

Figure 2.4 Hourly convergence bidding volumes and prices – January

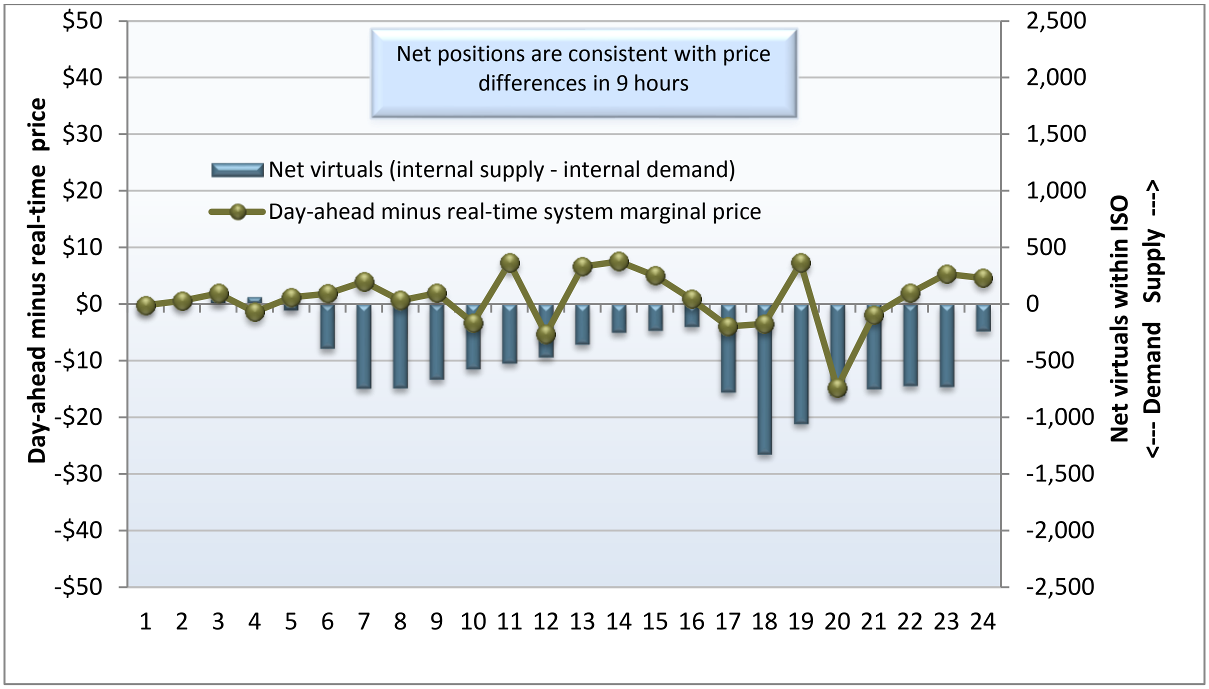


Figure 2.5 Hourly convergence bidding volumes and prices – February

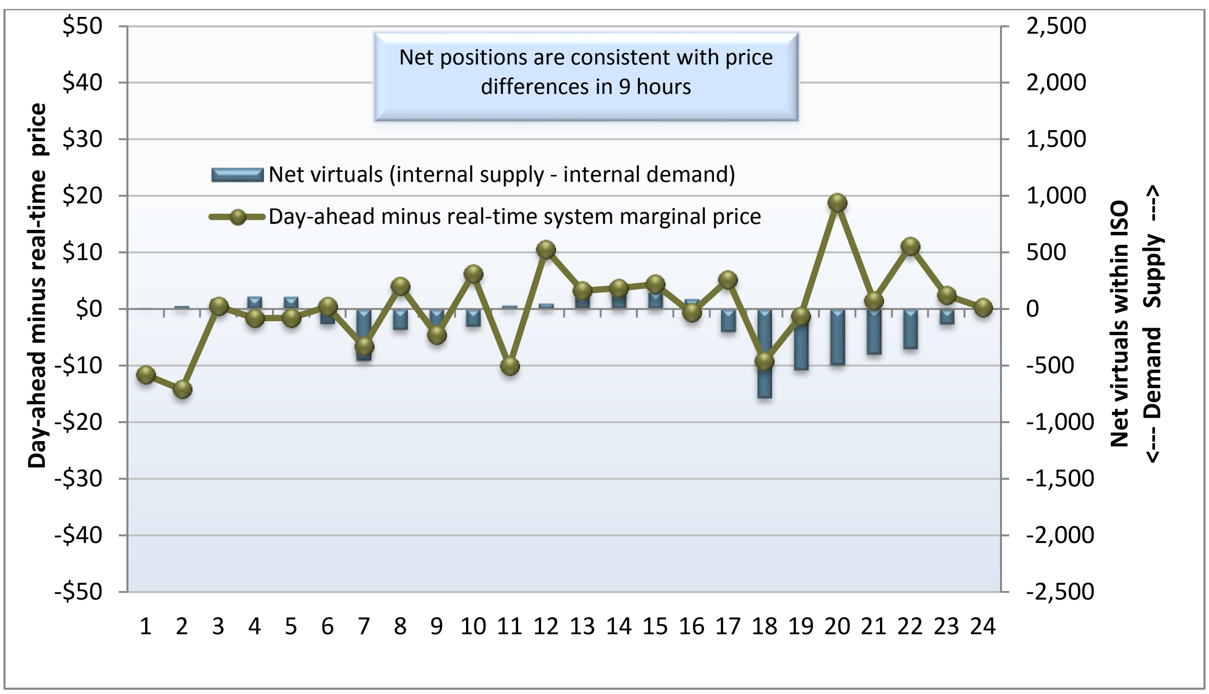
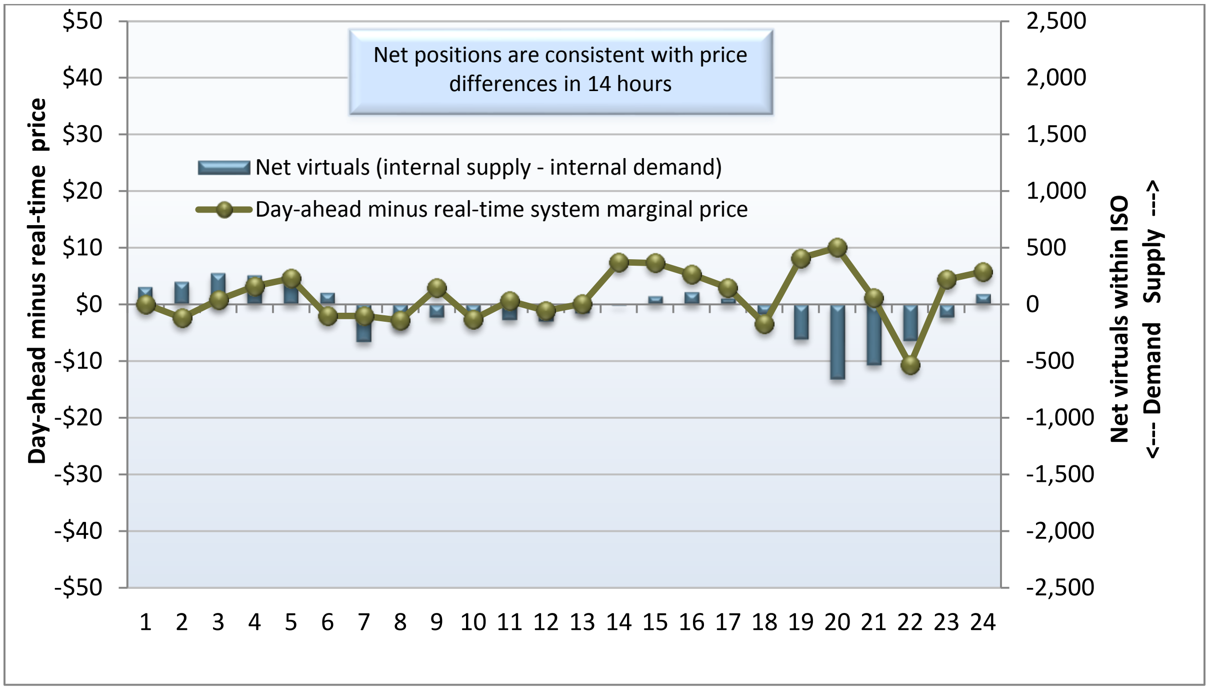


Figure 2.6 Hourly convergence bidding volumes and prices – March



Offsetting virtual supply and demand bids at internal points

Market participants can also hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual demand and supply bids at different internal locations during the same hour. These virtual demand and supply bids offset each other in terms of system energy. However, the combination of these offsetting bids can be profitable if there are differences in congestion in the day-ahead and real-time markets between these two locations.

The majority of cleared virtual bids in the first three months of 2013 were related to such offsetting bids. Figure 2.7 shows the average hourly volume of offsetting virtual supply and demand positions at internal locations. The dark blue and dark green bars represent the average hourly overlap between internal demand and internal supply by the same participants. The light blue bars represent the remaining portion of internal virtual supply that was not offset by internal virtual demand by the same participants. The light green bars represent the remaining portion of internal virtual demand that was not offset by internal virtual supply by the same participants.

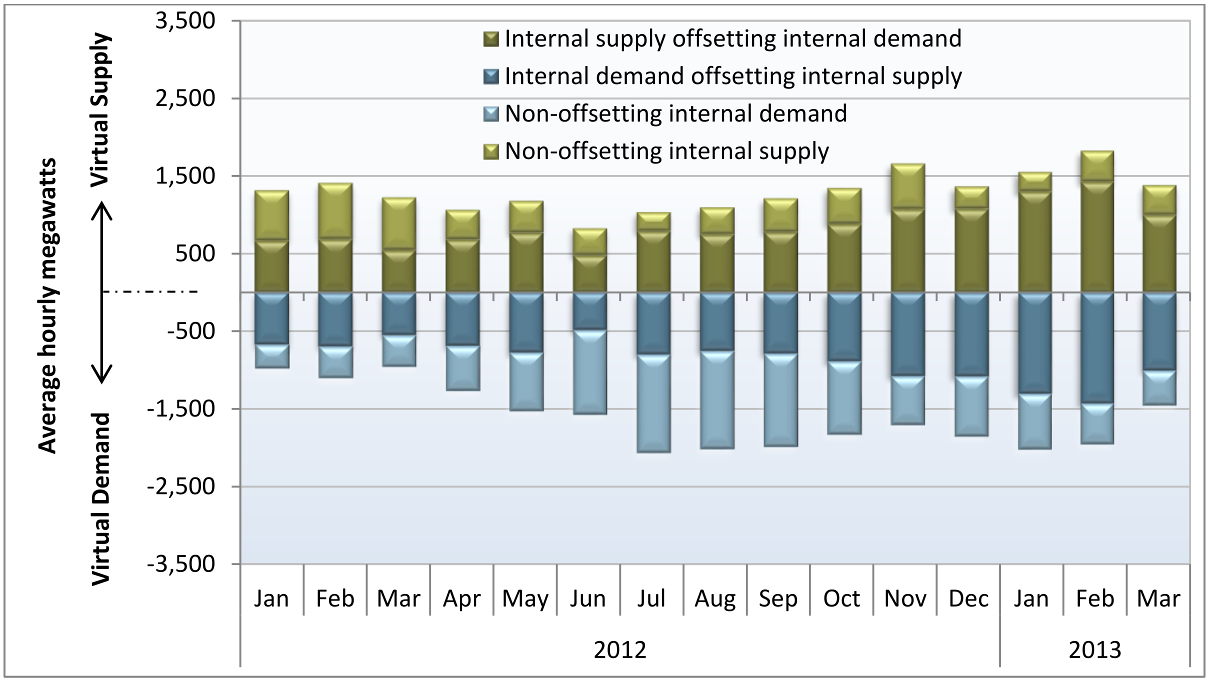
The following is shown in Figure 2.7:

- Offsetting virtual positions at internal locations accounted for an average of about 1,240 MW of virtual demand offset by 1,240 MW of virtual supply in each hour of the first quarter. These offsetting bids represent over 73 percent of all cleared internal virtual bids in the first quarter, which is up from 62 percent of bids in the previous quarter. This suggests that virtual bidding has been increasingly used to hedge or profit from internal congestion.

- Over time, the amount of offsetting internal virtual bidding positions taken by participants grew in volume and as a share of total internal virtual bids. In the first quarter, the share of offsetting internal virtual positions was higher than in all quarters of 2012.

- As discussed earlier in this chapter, the remaining virtual demand bids tended to be placed in peak hours during periods when average real-time prices tended to be higher than average day-ahead prices due to real-time price spikes. The remaining virtual supply bids tended to be placed in off-peak hours during periods when average real-time prices tended to be lower than average day-ahead prices.

Figure 2.7 Average hourly offsetting virtual supply and demand positions by same participants



2.2 Convergence bidding revenues

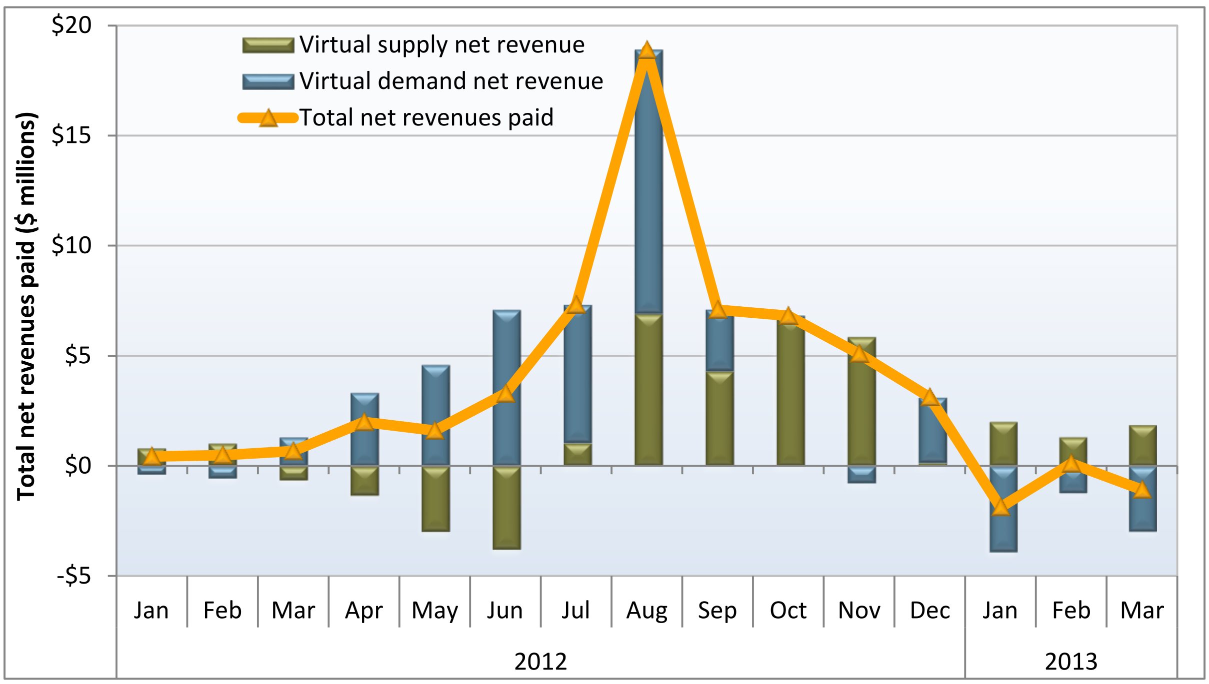
This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders. Unlike previous periods, participants engaged in convergence bidding in the first quarter paid more money into the ISO markets than what they received from the ISO markets. This resulted in negative net revenues (i.e., payments) of about $3 million, with most of these negative revenues associated with offsetting virtual bids.

Figure 2.8 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- Virtual supply revenues were consistently profitable in every month of the first quarter. These revenues were attributed to the higher frequency of negative real-time prices accompanied by congestion.

- Virtual demand was unprofitable in every month of the quarter. In total, virtual demand accounted for approximately $8 million in net payments to the ISO markets.
- Total net revenues paid to virtual bidders dropped from the previous quarter. This change was driven by losses on virtual demand positions. Revenues on virtual supply positions decreased substantially as well, but remained positive, overall.
- In the first quarter, convergence bidding entities lost around $3 million. Virtual demand accounted for over $8 million, while virtual supply generated net revenues of about $5 million. This trend reflects that virtual demand paid day-ahead prices that were higher than the real-time prices they received in the first quarter.

Figure 2.8 Total monthly net revenues paid from convergence bidding



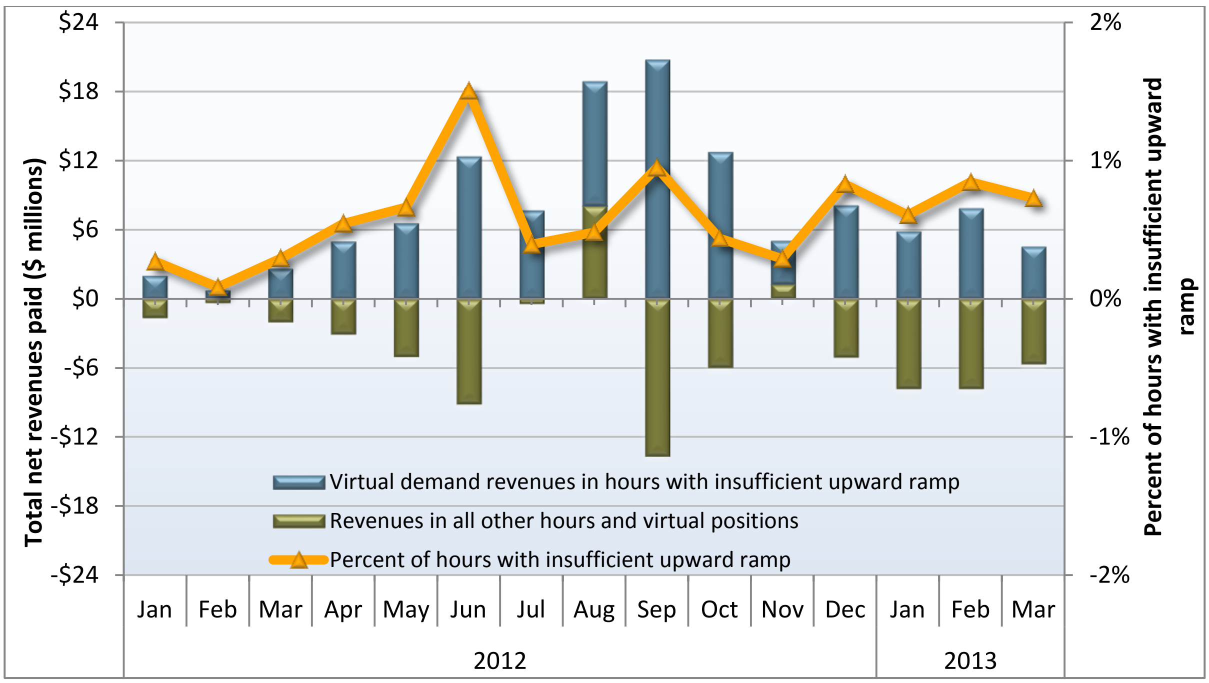
Net revenues at internal scheduling points

In the first quarter, virtual demand accounted for about 53 percent of cleared bids at internal locations, down from 59 percent in the previous quarter. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Almost all net revenues paid for these internal virtual demand positions have resulted from a relatively small portion of intervals when the system power balance constraint becomes binding because of insufficient upward ramping capacity or with congestion. Virtual supply bids are profitable when real-time prices drop below day-ahead prices. Usually, this happens during off-peak hours when over-generation can drive the prices down.

Figure 2.9 compares total net revenues paid out for internal virtual bids during hours when the power balance constraint was relaxed because of short-term shortages of upward ramping capacity with the overall net revenues of internal virtual bids during all other hours. As shown in Figure 2.9:

- Although upward ramping capacity was insufficient in just under 1 percent of the hours in the quarter, these hours accounted for all net revenues paid for internal virtual demand. Revenues paid for virtual demand during these brief but extreme price spikes can be high enough to outweigh losses when the day-ahead price exceeds the real-time market price. However, in the first quarter, the revenues paid out during these periods were not sufficient to offset virtual demand losses in other periods.
- Virtual demand net revenues were positive $18 million during intervals of insufficient upward ramp. All other virtual revenues were negative $21 million, driven by negative revenues of $26 million in virtual demand when sufficient upward ramping existed and positive $5 million in virtual supply revenues in the first quarter.

Figure 2.9 Net revenues paid for convergence bids at internal scheduling points



These price spikes are typically associated with brief shortages of ramping capacity. Virtual demand at internal scheduling points can potentially result in additional capacity being committed and available in the real-time market. In practice, however, the impact of internal virtual demand on real-time price spikes appears to have been limited by a number of factors:

- As discussed in prior sections of this chapter, the impact of virtual internal demand in the day-ahead market was offset significantly by virtual supply.
- Any additional capacity potentially made available by convergence bidding may not be enough to address the short-term ramping limitations in the real-time market.

Also, in the event of over-generation, real-time prices can be negative, but rarely fall below the bid floor of -$30/MWh. This diminishes the risk of market participants losing substantial amounts of money by bidding virtual demand as well as reduces the potential benefits to virtual supply bids at internal nodes.

Net revenues and volumes by participant type

DMM's analysis finds that most convergence bidding activity is conducted by entities engaging in pure financial trading that do not serve load or transact physical supply. These entities accounted for almost $2.1 million (60 percent) of the total convergence bidding settlements in the first quarter and a vast majority of the losses.

Table 2.1 compares the distribution of convergence bidding volumes and revenues among different groups of convergence bidding participants. The trading volumes show cleared virtual positions along with the corresponding revenues in millions of dollars.

DMM has defined financial entities as speculators who own no physical power and only participate in the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate as physical generators and load-serving entities, respectively. Marketers include participants on the inter-ties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO market.

As shown in Table 2.1, financial participants represent the largest segment of the virtual market and account for about 82 percent of volumes and about 60 percent of settlements. Marketers represent about 14 percent of the trading volumes and 30 percent of the settlement dollars. Generation owners and load-serving entities represent a small segment of the virtual market in volumes (with less than 5 percent) and about 10 percent of settlements. These physical participant positions in aggregate were the only profitable convergence bidding positions in the first quarter.

Table 2.1 Convergence bidding volumes and revenues by participant type (January - March)

Trading entities	Average hourly megawatts			Revenues ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	373	309	681	-7.0	4.8	-2.1
Marketer	61	57	119	-1.1	0.0	-1.1
Physical Generation	10	18	28	0.0	0.3	0.3
Physical Load	0	5	5	0.0	0.1	0.1
Total	**445**	**389**	**834**	**-8.1**	**5.2**	**-2.8**

3 Special Issues

3.1 Greenhouse gas cap-and-trade program

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

- The estimated cost of greenhouse gas emissions has been relatively stable, averaging \$14.55/mtCO_2e for the quarter.[18]
- When cap-and-trade requirements became effective in January 2013, the majority of gas unit bids increased by less than \$10/MWh to account for the greenhouse gas compliance in costs. This is consistent with the market cost of carbon emission credits for most generating units at this time.
- Based on statistical analysis of changes in energy prices following implementation of the cap-and-trade requirements, DMM estimates that the average wholesale electricity price impact is about \$6.15/MWh. This is also 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, imports increased in the first quarter of 2013 compared to the first quarter of 2012.

Background

California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, directs the California Air Resources Board (CARB) to develop regulation to reduce greenhouse gas emissions to 1990 levels by 2020. The cap-and-trade program is one of a suite of regulatory measures adopted by CARB to achieve this goal.

The cap-and-trade program covers major sources of greenhouse gas emissions including power plants.[19] The program includes an enforceable emissions cap that will decline over time. California will directly distribute and auction allowances, which are tradable permits equal to the emissions allowed under the cap.

The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the CPUC and other state entities. As part of the cap-and-trade program, the CARB allocated allowances to the state's electric distribution utilities to help compensate electricity customers for the costs that will

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

[19] The cap-and-trade program covers major sources of greenhouse gas emissions in California such as refineries, power plants, industrial facilities, and transportation fuels. For the electricity sector, the covered entity is the first deliverer of electricity. The first deliverer is defined in the regulation as the operator of an in-state electricity generator, or an electricity importer. The compliance obligation for first deliverers is based on the emissions that are a result of the electricity they place on the grid. The threshold for inclusion in the program for electricity generated from an in-state facility, and for imported electricity from a specified source, is 25,000 metric tons of annual greenhouse gas emissions. For imported electricity from unspecified sources, there is no threshold and all emissions are covered.

be incurred under cap and trade. The investor-owned electric utilities are required to sell all of their allowances at CARB's quarterly auctions, and the proceeds from the auction are to be used for the benefit of retail ratepayers, consistent with the goals of AB 32. Under a recent CPUC decision, revenue from carbon emission allowances sold at auction will be used to reduce offset impacts on retail costs.[20]

One allowance represents one metric ton of CO_2e. Sources under the cap are required to surrender allowances and offsets equal to their emissions at the end of each compliance period, with a partial annual surrender in the interim years. Electric generation resources emitting more than 25,000 metric tons of greenhouse gas annually, either within California or as imports into California, are covered under the first phase of the cap-and-trade program, which started on January 1, 2012, with enforceable compliance obligations beginning with emissions during 2013.

AB 32 requires CARB to minimize *leakage*, which is a reduction in greenhouse gas emissions within California that is offset by an increase in greenhouse gas emissions outside of California. The cap-and-trade program limits leakage in part by prohibiting *resource shuffling,* or substituting imports of lower gas emitting resources for imports actually sourced from higher emitting resources to avoid the cost of allowances. CARB has temporarily lifted the requirement that market participants submit annual legal documents stating that they have not engaged in resource shuffling in response to concerns that this requirement could limit imports into California leading to reliability problems in California and the western states.[21] CARB has also issued regulatory guidance concerning what activity it does not consider to constitute resource shuffling.[22]

Generators and importers that are covered by the regulations are required to submit allowances covering 30 percent of emissions in each year and the remainder of their emissions in the final year of each three year compliance period. In addition to allowances, covered generators and importers may submit emissions offsets to cover up to 8 percent of their emissions. The total cap on emissions is set to decline 2 percent annually through 2014 and 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 the three years subsequent to the vintage of the allowance.[23] *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

[20] Pursuant to CPUC decision Docket #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.

[21] See the letter from the CARB Chairman Mary Nichols to Commissioner Moeller of the Federal Energy Regulatory Commission dated August 16, 2012: http://www.arb.ca.gov/newsrel/images/2012/response.pdf.

[22] See CARB Regulatory Guidance document: What is Resource Shuffling, dated November 2012 http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf

[23] For example, a vintage 2013 allowance may be used for compliance during either the first (2013-2014), second (2015-2017), or third (2018-2020) compliance periods.

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).[24]

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 as the average of two market based indices.[25] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 3.1.

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. Over the entire first quarter, the index averaged \$14.55/mtCO_2e.

Figure 3.1 ISO's greenhouse gas allowance price index

[24] Details on each of the calculations may be found in the ISO Business Practice Manual for Market Instruments, Appendix K: http://bpmcm.caiso.com/BPM Document Library/Market Instruments/BPM_for_Market_Instruments_v26_clean.doc.

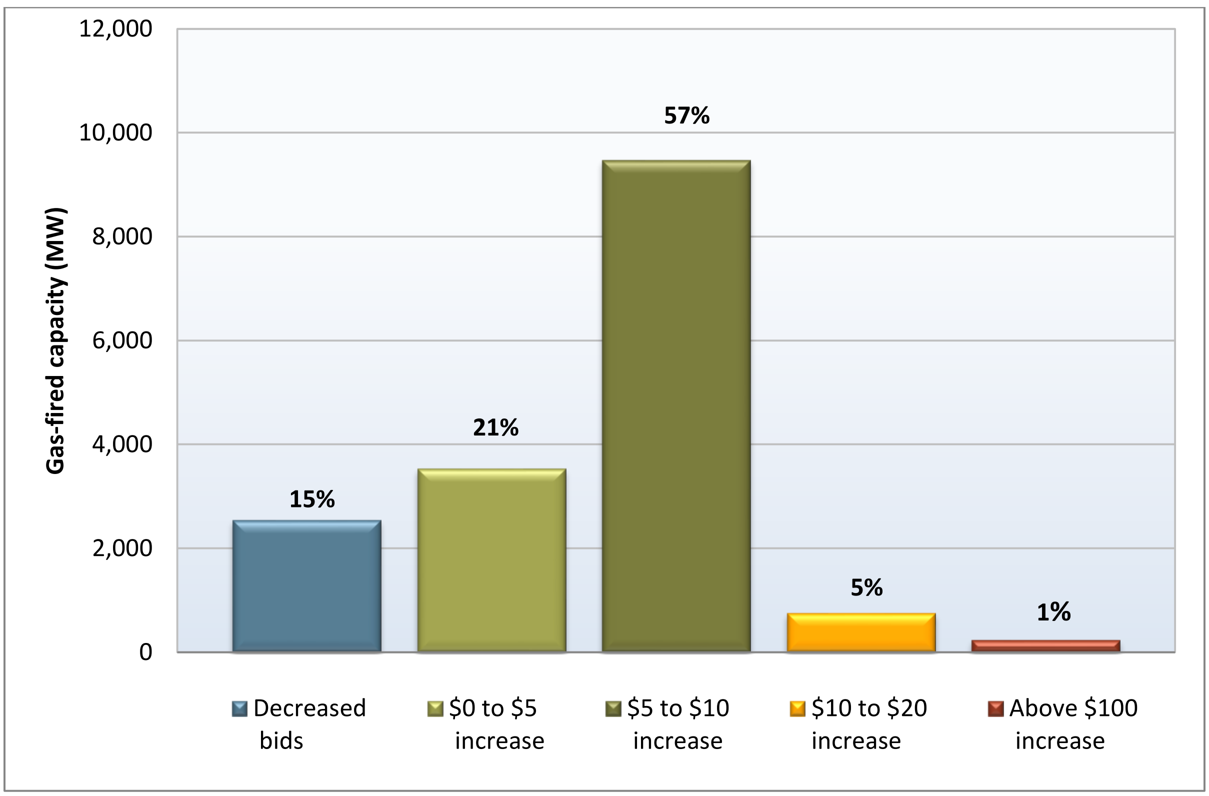
[25] The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, the ICE index is a settlement price but the ARGUS price was updated from a settlement price to a volume weighted price in mid-April of this year. For more information, see the ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

Changes in bids

One indicator of the impact that the state's greenhouse gas program had on the ISO market is the change in bid prices that occurred immediately following implementation of the program in January. To assess this impact, DMM compared bids of gas-fired generating bids in the last week of 2012 with bids during the second week of 2013. DMM excluded data for the first week of 2013 from this analysis since bidding by numerous units suggested some suppliers were still determining how to incorporate these cost into their bids. Resources with bids that were already high and not reflective of the resource's marginal costs prior to January 1, 2013, were excluded from the calculation. The units were grouped according to the changes in their bid costs.

Figure 3.2 summarizes results of this analysis of the changes in bids of the natural gas units covered under the cap-and-trade program. As shown in Figure 3.2, most of gas unit capacity covered by the greenhouse gas regulations increased their bids by less than \$10/MWh on average from the end of December 2012 to the beginning of January 2013.

Figure 3.2 Changes in bid prices of gas units after the implementation of the CO_2 market



About 85 percent of gas-fired capacity included in this analysis bid higher in January 2013. Around 80 percent of gas-fired capacity increased their bids by less than \$10/MWh. An increase of this magnitude is within the range of the additional cost associated with carbon emissions for generating units with different efficiencies given the cost of emission allowances during this time period (about \$14 to \$16/mtCO_2e).

For example, a price of $14/mtCO$_2$e equates to an additional cost of about $6/MWh for a relatively efficient unit with a heat rate of 8,000 Btu/kWh.[26] A price of $16/mtCO$_2$e equates to an additional cost of about $10/MWh for a less efficient unit with a heat rate of 12,000 Btu/kWh.[27]

Around 1 percent of the capacity increased their bids by more than $100/MWh. These increases were likely a result of other factors not attributable to the implementation of the cap-and-trade program.

Changes in market prices

Greenhouse gas compliance costs are expected to increase wholesale electricity costs as both market participant bids and the ISO's own calculation of default energy bids, resource commitment costs and generated bids increase to reflect the additional incremental variable cost of greenhouse gas compliance.

DMM has adopted two statistical approaches to estimate the impact of greenhouse gas costs on the ISO day-ahead market prices during the first quarter of greenhouse gas compliance. The first approach estimates an average price effect on the basis of implied heat rates. The second approach estimates an average price effect using linear regression analysis to control for both gas prices and load. Both approaches rely on the comparison of market data before cap-and-trade implementation with data from the first quarter of 2013.[28] Both methods produce similar results, which estimate an average greenhouse gas effect between $6.15/MWh and $6.21/MWh.

The energy price DMM chose to analyze was the day-ahead system marginal energy cost.[29] DMM chose to analyze changes in this value to limit the effects of transmission congestion when trying to isolate the effect of the greenhouse gas costs. While the system marginal energy cost does not eliminate transmission congestion effects, it can act as a reasonable benchmark for system prices.[30]

Implied heat rates

The first approach DMM employed to calculate the impact of greenhouse gas compliance on day-ahead energy prices is an analysis of *implied heat rates*. 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, in this case the hourly day-ahead system marginal energy price, by fuel price. Because natural gas is often on the margin in the ISO market, we use a weighted average of daily natural gas prices.[31] Figure 3.3 illustrates average weekly calculated implied heat rates for hours from November 2012 through March 2013.

[26] $14/mtCO$_2$e x 0.053165 mtCO$_2$/MMBtu x 8,000 Btu/kWh = $5.95/MWh

[27] $16/mtCO$_2$e x 0.053165 mtCO$_2$/MMBtu x 12,000 Btu/kWh = $10.21/MWh

[28] As demonstrated in Figure 3.1, the ISO's estimated greenhouse gas compliance cost does not exhibit sufficient variation to determine the impact based on minor fluctuations in this value alone.

[29] This is the energy component of each of the locational marginal prices within the ISO system and excludes both congestion and transmission loss related costs.

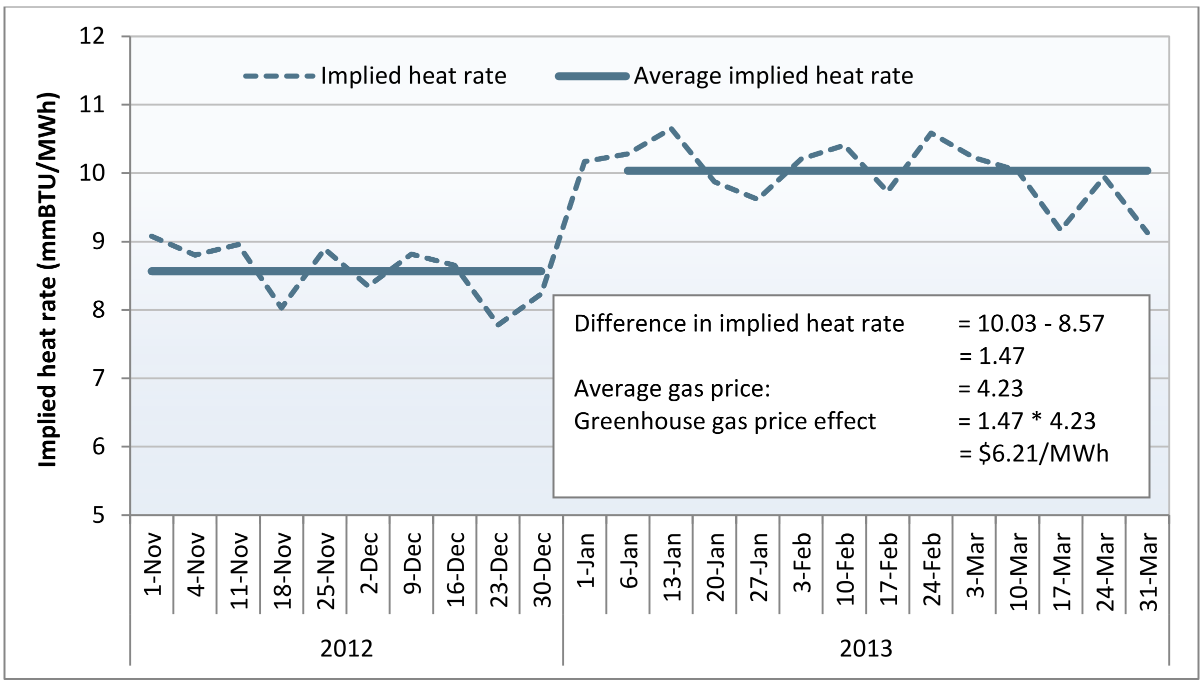
[30] For further discussion on the system marginal energy price, please see Appendix C of the ISO tariff: http://www.caiso.com/Documents/CombinedConformedTariff_Mar20_2013.pdf.

[31] For this calculation, DMM is using a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations.

The impact of the greenhouse gas compliance on energy costs may be calculated from the implied heat rate by taking the average implied heat rate before and after the implementation of the cap-and-trade program and then multiplying the difference by the cost of natural gas. As shown in Figure 3.3, using this approach DMM estimates that the impact of greenhouse gas compliance on ISO day-ahead system energy prices was $6.21/MWh.

This calculation does not take any factor other than the price of natural gas into account and will therefore attribute all non-fuel cost differences between the two periods to the greenhouse gas allowance price. DMM chose the final two months of 2012 as the period to compare to the first quarter of 2013 because loads were fairly comparable and the system faced a similar set of system conditions. Attributing the difference between the two periods to greenhouse gas compliance alone requires assuming that there are no systematic differences between the two periods other than the greenhouse gas allowance compliance.

Figure 3.3 Implied heat rates (system marginal energy price vs. average gas price)



Linear regression model

The second approach used by DMM to calculate the impact of greenhouse gas compliance on wholesale energy prices is a simple linear regression analysis. Average daily peak and off-peak system energy prices are modeled as a linear function of gas price indices, a non-linear function of load, peak hour status and a measure of the greenhouse gas compliance cost.

$$\text{Average Electricity Price} = \beta_0 + \beta_1\text{Gas}_{\text{PGE}} + \beta_2\text{Gas}_{\text{SCE1}} + \beta_3\text{Gas}_{\text{SCE2}} + \beta_4\text{Load} + \beta_5\text{Load}^2 + \beta_6\text{Peak} + \beta_7(\text{Peak} * \text{Gas}_{\text{PGE}}) + \beta_8(\text{Peak} * \text{Gas}_{\text{SCE1}}) + \beta_9(\text{Peak} * \text{Gas}_{\text{SCE2}}) + \beta_{10}(\text{Peak} * \text{Load}) + \beta_{11}(\text{Peak} * \text{Load}^2) + \beta_{12}\text{GHG} + \varepsilon$$

Using this model, DMM estimates that in the first quarter the impact of greenhouse gas compliance was \$6.15/MWh or \$0.42 per dollar of the allowance price. Although rough, our model predicts the average ISO day-ahead system energy prices fairly well, explaining approximately 83 percent of the variation in this measure in both models.[32] This simple initial analysis will be refined as further data becomes available.[33]

Both the implied heat rate methodology and statistical approach outlined above produce estimates that 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 \$14.55/mtCO$_2$e, an additional cost of \$6.19/MWh represents the emission cost of a gas-fired unit with a heat rate of 8,000 Btu/kWh.[34]

Import levels and participation

The ISO relies on a significant amount of power generated outside of California that is imported into the ISO at various inter-ties. Nearly 30 percent of the ISO power was served by imports in 2012, with many of these imports coming from outside California.[35] Prior to implementing the cap-and-trade program, stakeholders and regulators expressed concern that the rules related to resource shuffling would result in reduced imports into California as some participants would elect to no longer import.[36] 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 quarter of 2013, compared to the first quarter of 2012.

While differences in imports are difficult to specifically associate with implementation of the greenhouse gas program, there have been a few notable changes. There were a small number of participants that explicitly stopped importing as a result of the program. Specifically, imports into

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[32] In the first case, R^2 = 0.8287 and the adjusted R^2 = 0.8215. In the second case, R^2 = 0.8307 and the adjusted R^2 = 0.8236.

[33] Two alternative greenhouse gas measures are used. The first is an indicator variable equal to 1 in the greenhouse gas compliance period and 0 before that period. In this case, the coefficient estimate (β_{12} in the equation above) may be interpreted as the estimated average impact of greenhouse gas compliance on electricity prices (\$/MWh). The second greenhouse gas measure is the ISO's index of the greenhouse gas allowance value, set equal to zero before the compliance period. In this case, the coefficient estimate may be interpreted as the estimated impact of greenhouse gas compliance per allowance cost (\$/MWh divided by \$/mtCO$_2$e). As in the implied heat rate analysis above, DMM's regression results are based on values from November 2012 through March 2013 to limit bias introduced by factors not yet included in the model. We assume that load is not price responsive in the short-term, which allows us to estimate this model using ordinary least squares, rather than as a system of demand and supply equations. We also assume that the greenhouse gas allowance index price is exogenous rather than endogenously determined by electricity prices. In this analysis, we defined peak hours as those hours between 6:00 a.m. and 10:00 p.m. of each day and off-peak hours as all remaining hours. This is slightly different from the definition used for congestion revenue rights, which excludes Sundays and WECC holidays from the peak hour definition. Load is measured in thousands of MW and includes pumped load.

[34] \$14.55/mtCO$_2$e x 0.053165 mtCO$_2$/MMBtu x 8,000 Btu/kWh = \$6.19/MWh

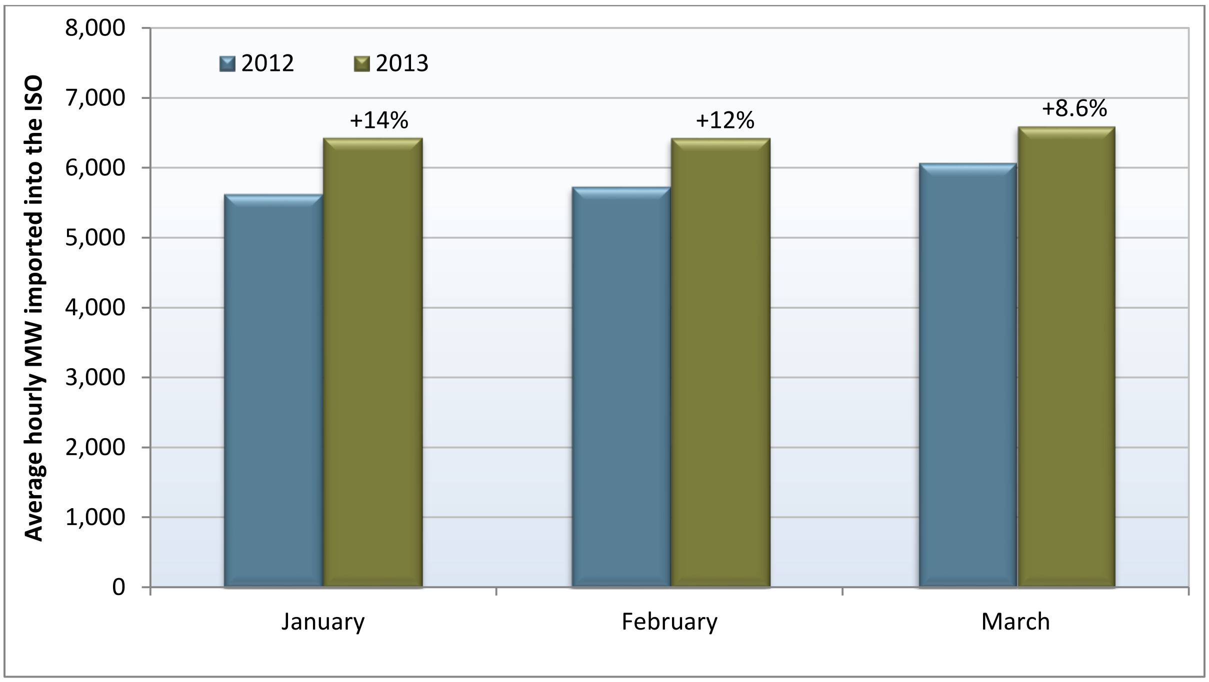
[35] See the DMM *2012 Annual Report on Market Issues and Performance*, Section 1.2 on supply conditions: http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

[36] See the August 6 letter from FERC Commissioner Moeller to Governor Brown: http://www.ferc.gov/about/com-mem/moeller/moeller-08-06-12.pdf.

California by public entities constitute the vast majority of the energy no longer being imported into California. However, even though some participants no longer import into California, new market entrants have begun to import into California including public entities and private companies. In total, these new entrants' imports exceeded the reduction in imports associated with the participants that are no longer importing into California.

In the first quarter, the total quantity of imports actually increased for each month in 2013 compared to the first quarter of 2012 (see Figure 3.4). Imports increased between 8 and 14 percent year-over-year during the same time period.

Figure 3.4 Comparison of imports on inter-ties in 2012 and 2013



3.2 Flexible ramping constraint performance

This section highlights the performance of the flexible ramping constraint over the last quarter. The key factors include the following observations:

- Flexible ramping costs were around $10 million in the first quarter compared to $20 million in all of 2012. This is an all-time high for the flexible ramping cost in a quarter.[37] For the sake of comparison, spinning reserve costs were around $6 million in the first quarter.

[37] The ISO filed in July and implemented in the fall a more comprehensive settlement approach. DMM has incorporated this new approach in its calculations. See the following for further information on the new settlement approach: http://www.caiso.com/Documents/July272012Offer-SettlementRegarding-ISOFlexibleRampingConstraintAmendment-DocketNoER12-50-000.pdf.

- The ISO operators continued to increase the flexible ramping requirement more consistently during the morning and evening ramping periods of the day in the first quarter. This caused both the procurement level and flexible ramping shadow prices to increase. Together, this caused the overall costs to increase notably.
- Almost half of flexible ramping constraint payments were during intervals when the system was unable to procure enough flexible ramping capacity to meet the requirement.
- Overall, 55 percent of the flexible ramping capacity was procured in the northern part of the state, which can be stranded when congestion occurs in the southern part of the state.

The ISO has begun the process of reviewing and evaluating how the flexible ramping constraint has affected the unit commitment decisions made in real time.[38] The initial results have indicated that effective capacity was added to meet the flexible ramping requirement.

Background

In December 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch markets. The constraint is only applied to internal generation and proxy demand response resources and not to external resources. The default requirement is currently set to around 300 MW.

If there is sufficient capacity already on-line, the ISO does not commit additional resources in the system, which often leads to a low (or often zero) shadow price for the procured flexible ramping capacity. During intervals when there is not enough 15-minute dispatchable capacity available among the committed units, the ISO can commit additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. Units committed to meet the flexible ramping requirement can be eligible for bid cost recovery payments in real time.[39] A procurement shortfall of flexible ramping capacity will occur where there is a shortage of available supply bids to meet the flexible ramping requirement or when there is energy scarcity in the 15-minute real-time pre-dispatch.[40]

Payments to generators

The total payments for flexible ramping resources in the first quarter were around $10 million, compared to around $2 million in the fourth quarter of 2012 and $20 million in total in 2012. The first quarter cost was the highest since the flexible ramping constraint was implemented in December 2011.[41] For the sake of comparison, costs for spinning reserves totaled about $6 million in the first quarter. Around 50 percent of flexible ramping payments to generators occurred when the system was unable to procure enough flexible ramping capacity to meet the requirement.

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[38] The ISO has begun to review commitment decisions by doing sample reruns of the 15-minute pre-dispatch market. DMM reviewed the initial results and offered suggestion for further analysis.

[39] Further detailed information on the flexible ramping constraint implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/FlexibleRampingConstraint.aspx.

[40] The penalty price associated with procurement shortfalls is set to just under $250.

[41] There are also secondary costs, such as those related to bid cost recovery payments to cover the commitment costs of the units committed by the constraint and additional ancillary services payments. Assessment of these costs are complex and beyond the scope of this analysis.

Figure 3.1 provides a review of the monthly flexible ramping constraint activity in the 15-minute real-time market since the beginning of 2012. The table highlights the following:

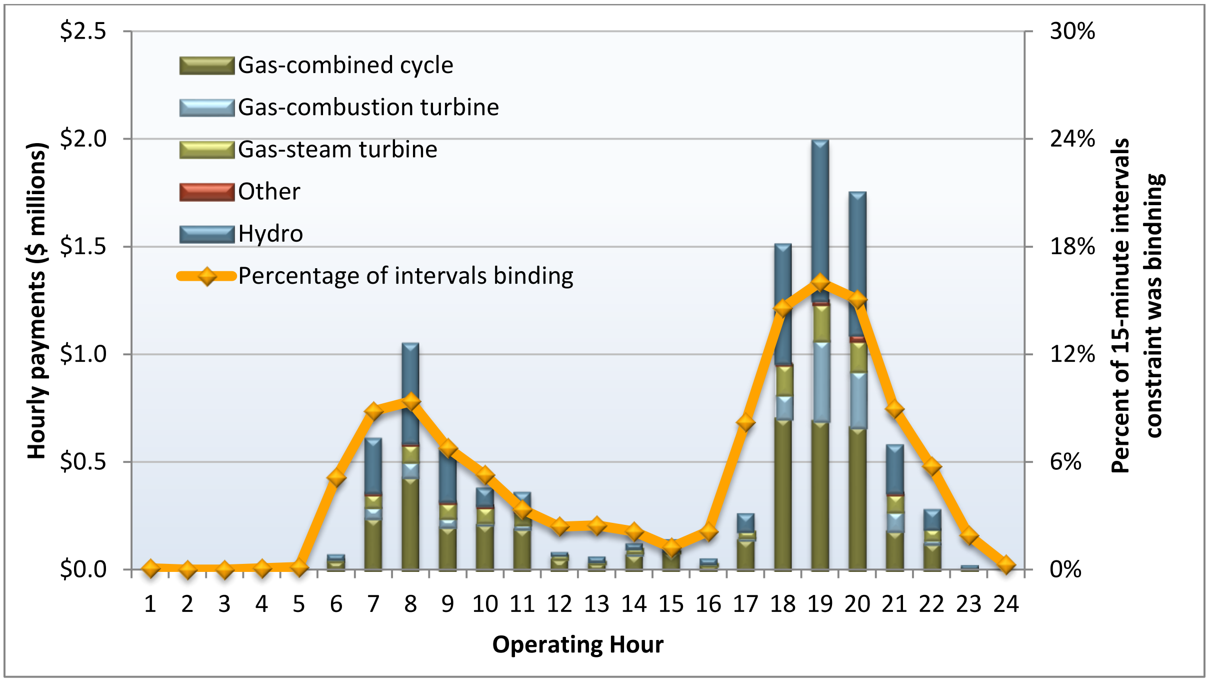
- The frequency of intervals where the flexible ramping constraint was binding was around 17 percent, compared to 7 percent in the previous quarter.
- The frequency of procurement shortfalls was over 2 percent of all 15-minute intervals in the fourth quarter, compared to approximately 1 percent in the previous quarter.
- The total payments to generators for the flexible ramping constraint were around $10 million, compared to around $2 million in the previous quarter and $6 million in the first quarter of 2012.
- The average shadow price that occurred when the flexible ramping constraint was binding increased from $51/MWh in the previous quarter to $61/MWh in the first quarter.

Most payments for ramping capacity occurred during the evening peak hours. In addition, most payments were for natural gas-fired resources. Figure 3.5 shows the hourly flexible ramping payment distribution during the first quarter broken down by technology type. As shown in the graph, the highest payment periods were during hours ending 17 through 21. In addition, natural gas-fired capacity accounted for about 62 percent of these payments with hydro-electric capacity accounting for 36 percent.

Table 3.1 Flexible ramping constraint monthly summary

Year	Month	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall (%)	Average shadow price when binding ($/MWh)
2012	Jan	$2.45	17%	1.0%	$38.44
2012	Feb	$1.46	8%	1.3%	$77.37
2012	Mar	$1.90	12%	1.0%	$42.75
2012	Apr	$3.37	22%	1.5%	$39.86
2012	May	$4.11	23%	6.0%	$79.48
2012	Jun	$1.49	13%	2.3%	$52.18
2012	Jul	$1.01	8%	1.4%	$47.94
2012	Aug	$0.77	7%	1.2%	$34.81
2012	Sep	$1.03	13%	0.8%	$32.54
2012	Oct	$0.95	9%	1.0%	$39.19
2012	Nov	$0.23	4%	0.5%	$53.34
2012	Dec	$1.09	9%	1.6%	$61.84
2013	Jan	$1.62	14%	2.2%	$59.46
2013	Feb	$3.45	19%	2.0%	$60.46
2013	Mar	$4.85	19%	3.1%	$63.06

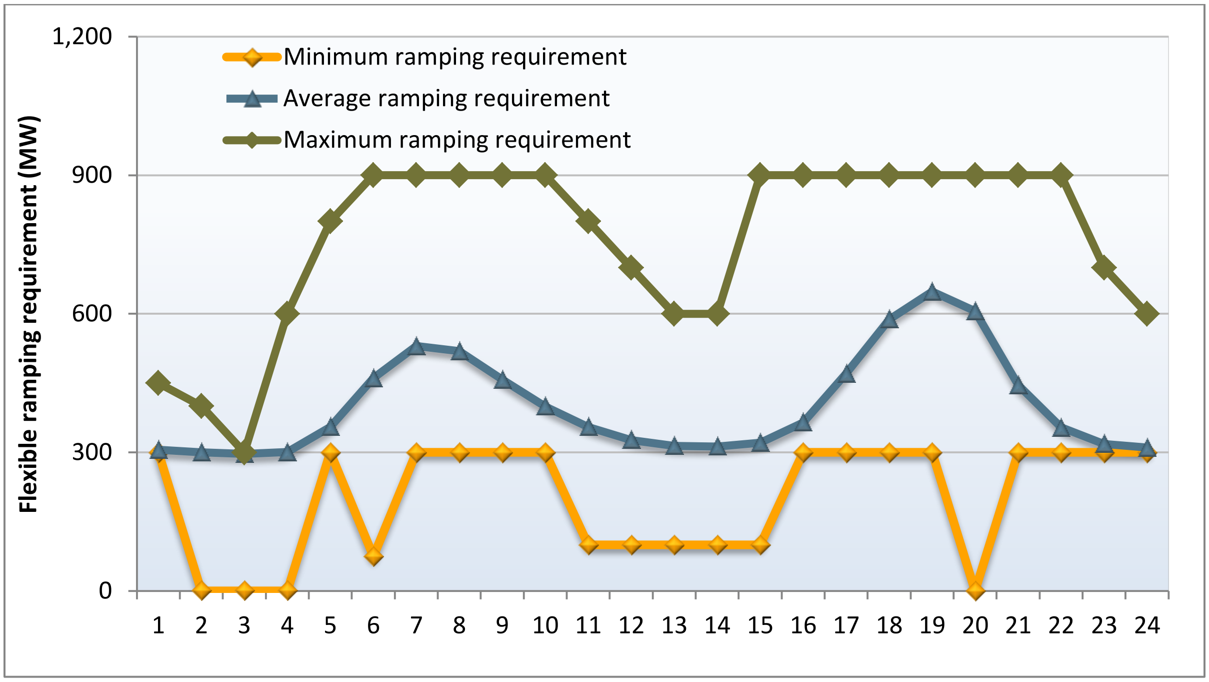
Figure 3.5 Hourly flexible ramping constraint payments to generators (January – March)



As noted in Section 1.5, the ISO is attempting to decrease the frequency and volumes of exceptional dispatch. As a result, the ISO operators used other market tools to deal with reliability concerns. Accordingly, the operators started to increase the flexible ramping requirement more frequently to let the market procure more system ramping resources in real time. These efforts notably decreased the amount of exceptional dispatch.

Figure 3.4 shows the hourly average flexible ramping requirement values in the first quarter. The hourly ramping requirement ranged from a minimum of 0 MW to a maximum of 900 MW. On average, the requirement was set to around 300 MW in the early morning hours and above 500 MW in the morning and evening load ramping hours. These changes to the ramping requirement increased both the procurement level and cost of flexible ramping in the first quarter.

Figure 3.6 Hourly average flexible ramping requirement values (January – March)



Real-time use of flexible ramping capacity

A useful metric for determining how effective the flexible ramping constraint is in procuring ramping capacity when needed is to determine how much of the ramping is utilized in real time. DMM uses the ISO's methodology along with settlement data to calculate the flexible ramping capacity utilization. The metric determines how much of the procured flexible ramping capacity in the 15-minute real-time pre-dispatch was used in the 5-minute real-time dispatch. The utilization is a function of prevailing system conditions, including load and generation levels.

The average utilization of procured flexible ramping ranged from 16 percent in the early morning to 48 percent in the late evening. This pattern was similar to the overall pattern in 2012.

Flexible ramping regional procurement

The flexible ramping constraint is designed to address system ramping needs. However, to the extent that flexible ramping capacity is procured in transmission constrained areas, the flexible ramping constraint can also help to resolve regional ramping needs.

Figure 3.5 shows the procurement of flexible ramping capacity by investor-owned utility area. In the first quarter, around 55 percent of the capacity procured for the flexible ramping constraint was in the Pacific Gas and Electric area. Because flexible capacity is deployed during tight system-wide conditions, the majority of this capacity cannot be utilized when there is congestion in the southern part of the state, which occurred frequently in the first quarter (see Section 1.3). On average, around 95 MW and 98 MW of flexible ramping capacity were procured in the San Diego and SCE areas, respectively. Considering that congestion primarily affected the SCE area in the first quarter, the procured ramping megawatts had a limited role in resolving the 5-minute congestion related ramping issues.

Figure 3.7 Flexible ramping constraint by investor-owned utility area