California ISO
Shaping a Renewed Future

California Independent System Operator Corporation

California ISO

Q4 2012 Report on Market Issues and Performance

February 12, 2013

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Executive summary

This report provides an overview of general market performance during the fourth quarter of 2012 (October – December) and recommendations by the Department of Market Monitoring (DMM). Key trends in market performance include the following:

- Improved convergence of average day-ahead and real-time system energy prices
- Continued divergence between hour-ahead and real-time system prices
- Continued congestion resulting from import limitations and outages
- Increased differences in congestion between the day-ahead and real-time markets
- Continued high levels of real-time congestion imbalance costs
- Increased payments for residual unit commitment bid cost recovery
- Increased convergence bids and profits from offsetting virtual supply and demand bids designed to take advantage of high real-time congestion
- Decreased convergence bidding net revenues on overall positions
- Continued reductions in ancillary service requirements in real-time below levels procured in the day-ahead market

In this report, DMM recommends that the ISO:

- Avoid over-procurement of ancillary services in the day-ahead market by applying the new requirement method for calculating real-time ancillary services to the day-ahead market
- Review how the flexible ramping constraint has affected the unit commitment decisions made in real-time
- Continue to address the causes of systematic price divergence through procedure, modeling, forecasting and market design enhancements

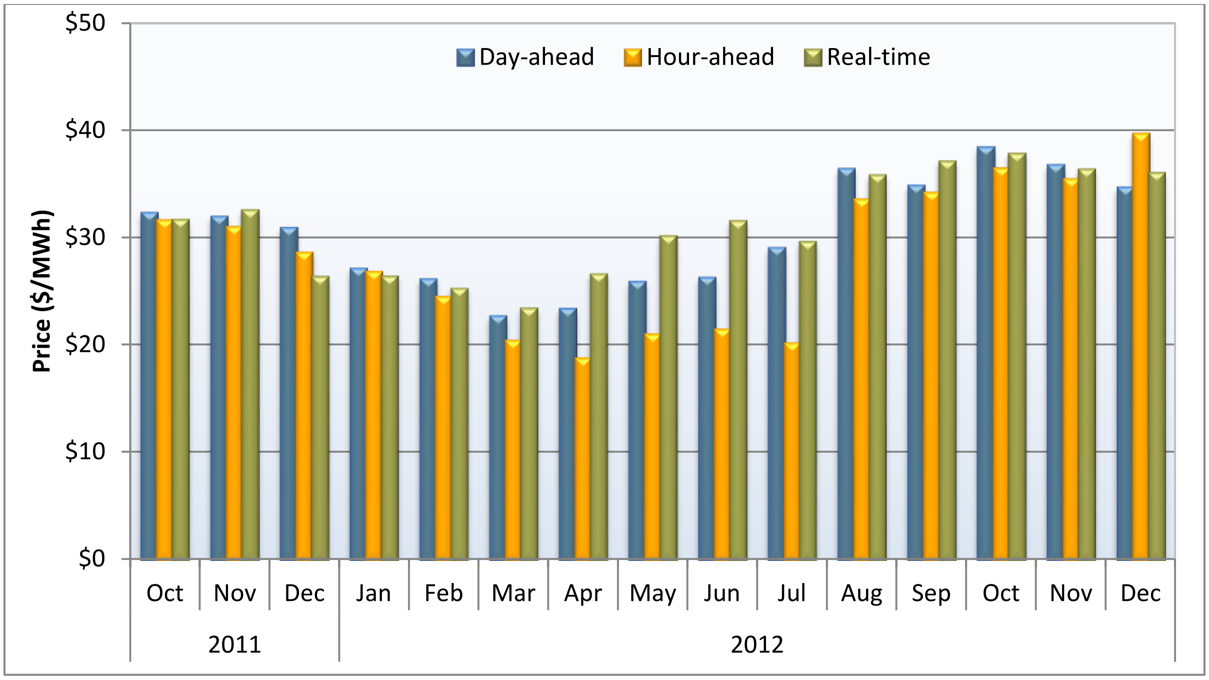
Energy market performance

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

Improved convergence of system energy prices between day-ahead and real-time. Average system energy prices in the real-time market (excluding congestion) were close to average prices in the day-ahead market (see Figure E.1). This trend was driven largely 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 October and November, but were higher than real-time system energy prices in December (as seen in Figure E.1). These differences were most pronounced in the evening ramp period and were influenced by extreme price differences in a relatively small number of instances.

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

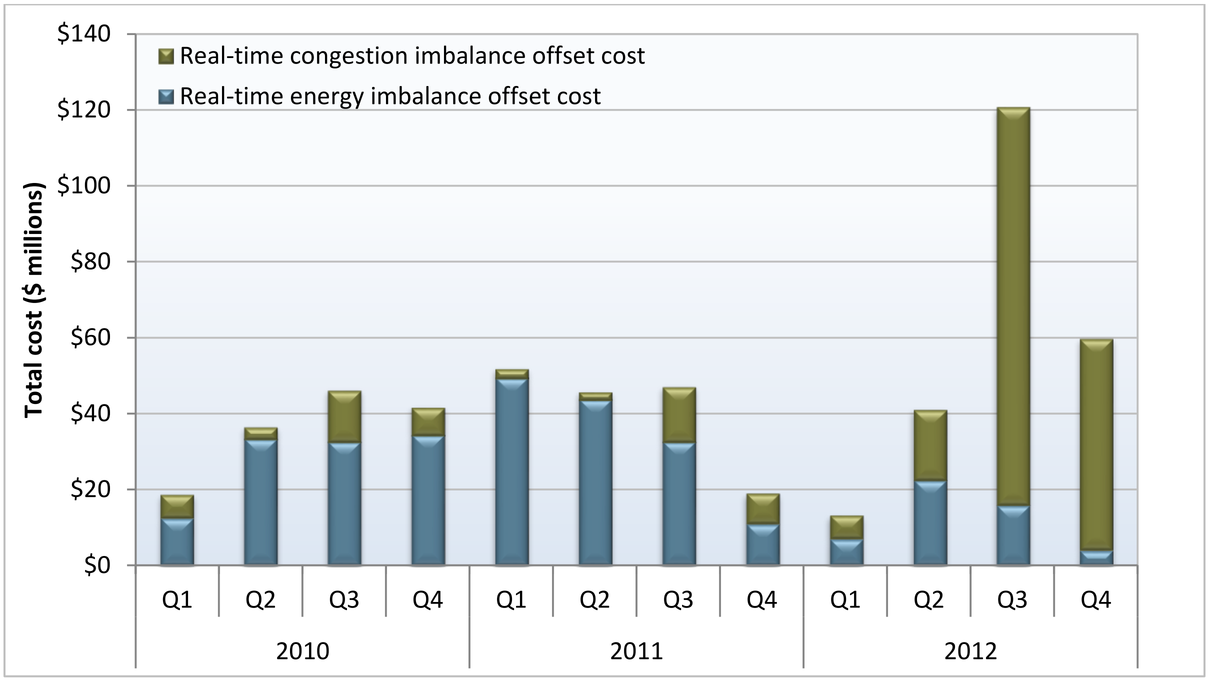


Congestion continued to influence day-ahead and real-time prices. Congestion within the ISO system continued to impact overall prices in the fourth quarter in the day-ahead and real-time markets. Congestion affected day-ahead and real-time prices by about 4 to 6 percent in both the day-ahead and real-time markets. For the quarter, congestion caused both the San Diego Gas & Electric and Southern California Edison prices to increase and the Pacific Gas and Electric price to decrease on average. Import limitations and outages primarily caused congestion throughout the system.

Increased differences in congestion between the day-ahead and real-time markets. Since April, differences between the day-ahead and real-time congestion have continued to increase. Congestion occurs more frequently in the day-ahead, 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.

Real-time congestion imbalance offset costs remained high. Real-time congestion imbalance costs totaled about $56 million in the fourth quarter (see Figure E.2). This is down from over $100 million in the third quarter, but is still the second highest quarterly value since the nodal market began in April 2009. These costs remained high as systematic differences in congestion occurred between the day-ahead and real-time markets on select constraints. These costs were also influenced by forced transmission outages and adjustments (or *conforming)* of line limits by ISO operators. While real-time congestion imbalance costs remained high, real-time energy offset costs were low and totaled around $4 million. This is the lowest quarterly value since the nodal market began.

Figure E.2 Real-time imbalance offset costs



Bid cost recovery payments for residual unit commitments increased. Total bid cost recovery payments in the fourth quarter were similar to the third quarter at $29 million. Real-time bid cost recovery payments decreased by 37 percent to $11 million in the fourth quarter. However, the residual unit commitment portion of the bid cost recovery payments increased to around $7 million, compared to $1.6 million in the first nine months of 2012. This increase resulted from higher regional residual unit commitment requirements established by the ISO to address capability in preparation of a transmission contingency event in the PG&E area as a result of a major transmission outage. This increase in residual unit commitment requirements began in mid-October and continued for a month. The ISO then began to model the capability in case of contingency need as a minimum online constraint north of Path 15.

Convergence bidding

Convergence bidding within the ISO also provides a mechanism for participants to hedge or speculate based on potential price differences of congestion at different locations or in system energy prices between the day-ahead and real-time markets.[1] Convergence bidding activity was marked by several key trends in the fourth quarter.

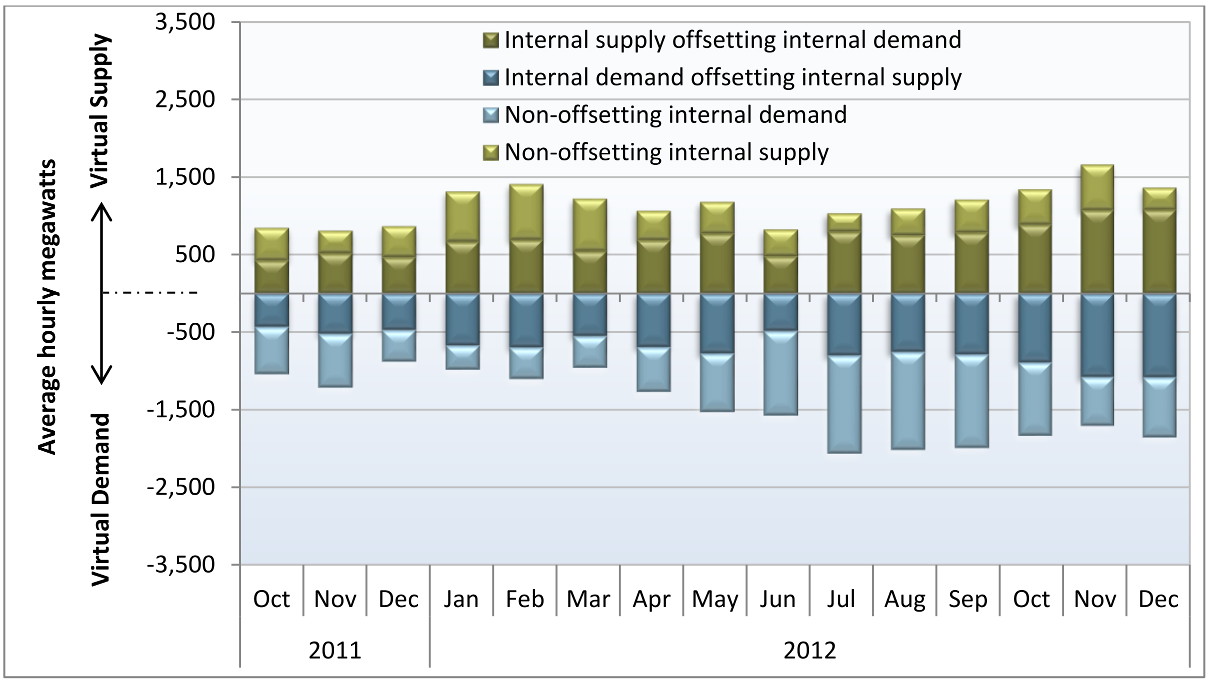
Increased convergence bidding designed to take advantage of congestion. Market participants can hedge (speculate) on potential congestion between points within the ISO system by placing an equal amount of virtual demand and supply bids at different internal locations during the same hour. This type of offsetting virtual position at internal locations accounted for an average of about 1,000 MW of demand offset by over 1,000 MW of virtual supply at other locations per hour in the fourth quarter (see

[1] The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was temporarily suspended by FERC on November 28, 2011. Thus, 2012 represents the first full year with virtual bidding within the ISO system but not at the inter-ties.

Figure E.3). These offsetting bids represented over 60 percent of all cleared bids in the fourth quarter, up from 50 percent in the third quarter. Net revenues associated with offsetting convergence bids totaled almost $16 million in the fourth quarter. These net revenues were driven primarily by real-time congestion prices on a few constraints that were systematically higher than in the day-ahead market.

Decreased net revenues associated with the net convergence bidding position. While most convergence bids were associated with offsetting virtual supply and demand positions, the overall quantity of virtual demand exceeded virtual supply, particularly in peak hours. During some off-peak hours, however, virtual supply exceeded virtual demand. In total, convergence bids made about $15 million in net revenues in the fourth quarter, which was down from $33 million in the third quarter. Even so, the fourth quarter net revenues were higher than the net revenues made by convergence bids in the first half of 2012.

Figure E.3 Average hourly offsetting virtual supply and demand positions by same participants



Other issues and recommendations

Ancillary services requirements. As discussed in DMM's third quarter report, the ISO implemented in late August an automated feature known as the *ancillary service requirement setter.* This automated feature has been utilized to assess the requirement for spinning and non-spinning reserves in the 15-minute real-time pre-dispatch market. The process to set the day-ahead requirement has not changed as the new feature has not been used in the day-ahead market. Using different requirement methodologies between the two markets has systematically caused differences in procurement of ancillary services. The real-time market procured an average of 86 MW fewer spinning and non-spinning reserves for the quarter. DMM has recommended and the ISO plans to enhance and then use this new feature in the day-ahead market in order to better align the procurement of ancillary services between the day-ahead and real-time markets.

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. As in previous quarters, the flexible ramping constraint was less effective in addressing real-time price volatility during periods of congestion and under tight capacity conditions. The flexible ramping constraint is applied on a system-wide basis and was not designed to address zonal or local ramping issues. The effectiveness of the flexible ramping constraint for system ramp did appear to improve the magnitude of the relaxations and level of price spikes when ISO operators shaped the requirement to better meet evening ramping needs. Total payments made for flexible ramping capacity during the fourth quarter were almost $3 million. By comparison, payments for spinning reserve totaled about $10 million for the same period. DMM has recommended that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in real-time. DMM believes this is an important measure of the overall effectiveness of the constraint not yet assessed by the ISO.[2]

Enhancements to address price convergence. DMM continues to stress the importance of improving price convergence. In particular, congestion differences have also played a growing role in increasing uplifts of the last few quarters. DMM is supportive of the steps that the ISO has undertaken to address these differences. These steps include:

- **Conforming transmission limits in the day-ahead and hour-ahead markets to better align resources to deal with anticipated transmission conditions in real-time.** DMM is supportive of this change as it allows the day-ahead to better reflect expected conditions in real time, which allows for better unit commitment and inter-tie scheduling to resolve real-time situations.

- **Implementing the transmission reliability margin (TRM).**[3] This allows the ISO to create a transmission margin on inter-ties in the hour-ahead market to better allow for management of unscheduled flows before real time. The ISO implemented this in the third quarter on selected paths.

- **Enhancing compensating injections to reduce variability.** As noted in the DMM 2012 third quarter report, the ISO enhanced compensating injections to reduce its variability from one 15-minute interval to another.[4] DMM observed that the improvements to variability continued throughout the fourth quarter.

- **Taking steps to modify transmission constraint relaxation parameters.** The ISO Board of Governors approved at its December meeting modifications to the transmission constraint relaxation parameter to address the uneconomic effect of diminishing returns when high shadow prices are produced with insignificant amount of flow reductions.[5]

[2] The ISO is planning to add new model functionality to indicate which units were added by the flexible ramping constraint.

[3] For further detail on transmission reliability margin, see the following: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionReliabilityMargin.aspx.

[4] For more information, see Section 3.2 of DMM's *Q3 2012 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2012ThirdQuarterReport-MarketIssues-Performance-Nov2012.pdf.

[5] For more information, see the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionConstraintRelaxationParameterChange.aspx.

1 Market performance

This section highlights key performance indicators of the markets in the fourth quarter. The highlights include:

- Improved convergence of system energy prices between the day-ahead and real-time markets, particularly in peak hours
- Increased divergence between system hour-ahead and real-time prices
- Decreased levels of real-time price spikes
- Continued differences in congestion between the day-ahead and real-time markets
- Continued high levels of real-time imbalance costs
- Decreases in real-time bid cost recovery payments, but increases in residual unit commitment bid cost recovery payments

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. Price convergence between the markets ensures efficient commitment of internal and external generating resources.

Average real-time price levels were mixed compared to day-ahead and hour-ahead prices during the quarter, showing improvement in some metrics and continued divergence in others. Figure 1.1 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively.[6]

- In peak and off-peak periods in the third quarter, hour-ahead prices remained lower than day-ahead prices in all months and periods but on-peak hours in December. Hour-ahead prices in the fourth quarter averaged almost $2/MWh higher than day-ahead prices in peak hours and just over $1/MWh lower in off-peak hours. In December 2012, the difference in hour-ahead and day-ahead prices was largest for peak hours.
- Average system prices in the 5-minute real-time market were close to day-ahead prices in most periods, except for peak and off-peak hours in October.
- Average system prices in the 5-minute real-time market were below hour-ahead prices in peak hours for the quarter. Average hour-ahead prices were driven by multiple instances of extreme network congestion that occurred in a few days and hours in the second half of December. At the monthly level, the largest average difference was over $9/MWh during peak hours in December. If these outliers were removed, hour-ahead prices would have been close to average real-time prices.

[6] DMM has switched its price analysis to the system marginal energy price, which is not affected by congestion or losses.

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

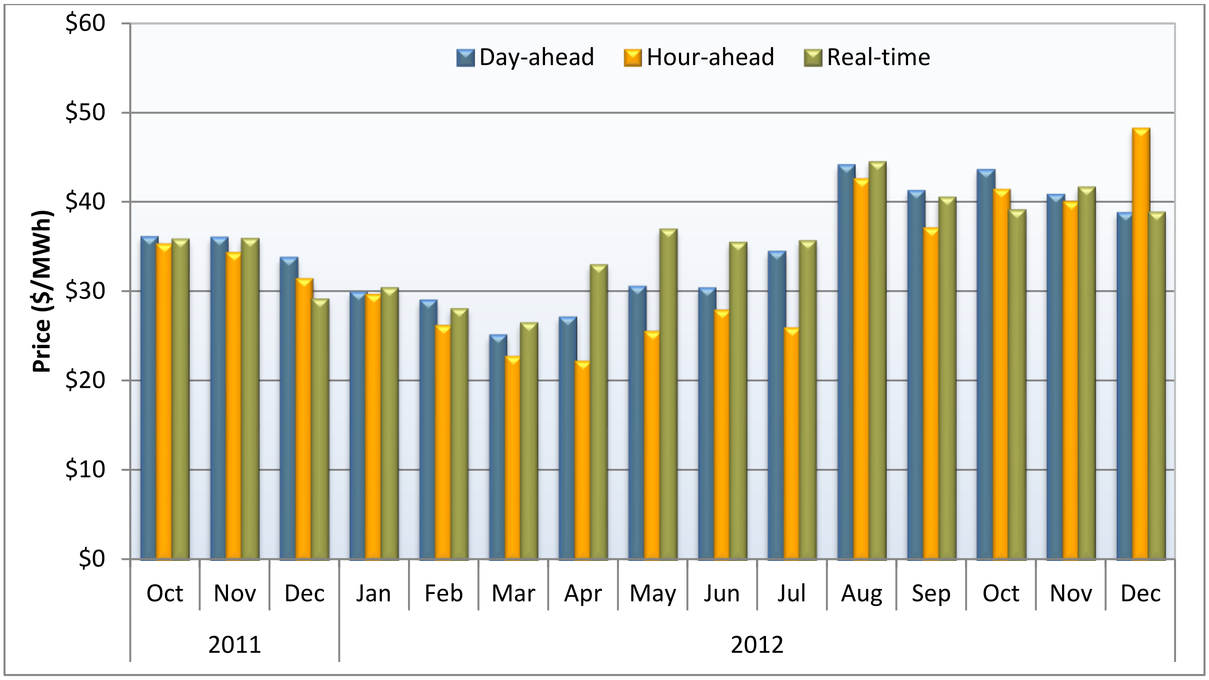


Figure 1.2 Average monthly off-peak prices – system marginal energy price

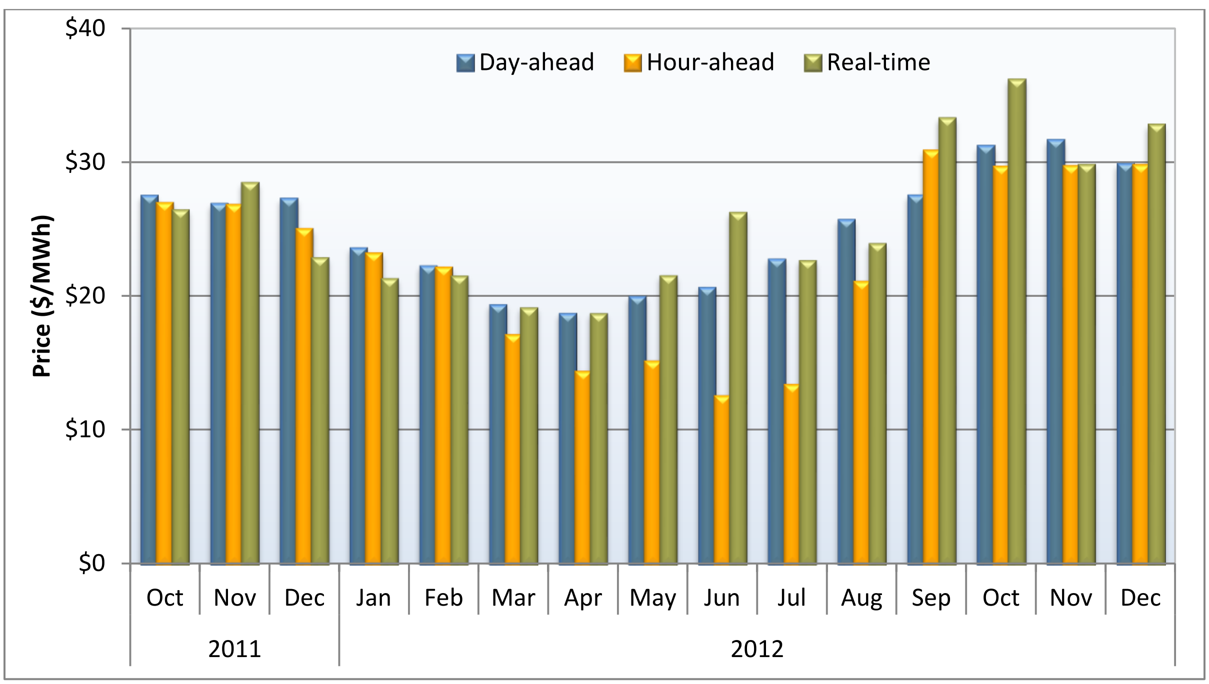


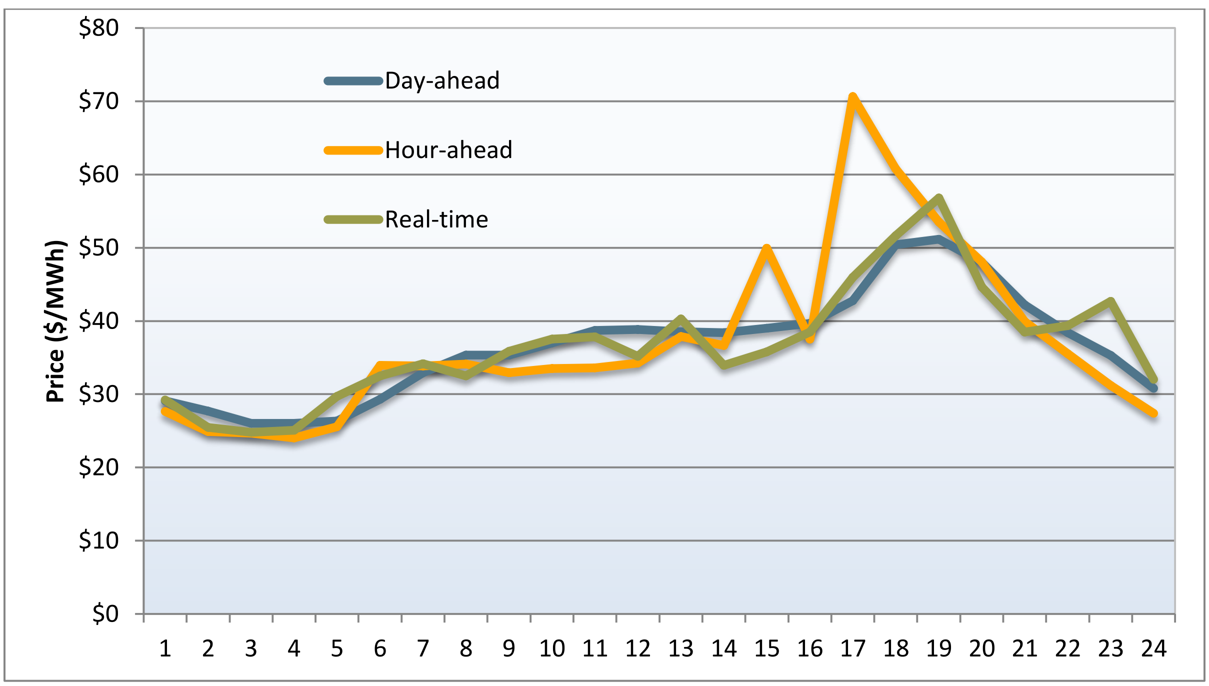
Figure 1.1 and Figure 1.2 show continued price divergence between average hour-ahead and real-time market prices during the fourth quarter. Figure 1.3 and Figure 1.4 further highlight that systematic differences between hour-ahead and real-time system prices remained in the fourth quarter.

Figure 1.3 shows average hourly prices for the fourth quarter. Real-time prices were close to hour-ahead prices during hours ending 1 through 8 and hours ending 19 and 21, but were over $25/MWh lower in hours ending 17 and 18. Hourly average real-time prices were close to day-ahead prices for much of the day. In the fourth quarter, real-time prices fluctuated around day-ahead prices. Meanwhile, hour-ahead prices were lower than either day-ahead or real-time prices for most of the day in the fourth quarter, except for hours ending 15, 17 and 18.

Figure 1.4 highlights the magnitude of price differences for all hours in the hour-ahead and real-time markets based on this simple average of price differences in these markets. Based on the simple average (green line), price divergence peaked in December and shifted to an average difference of about -$2.50/MWh for the quarter. The trend showed signs of price convergence, on average, between September and November.

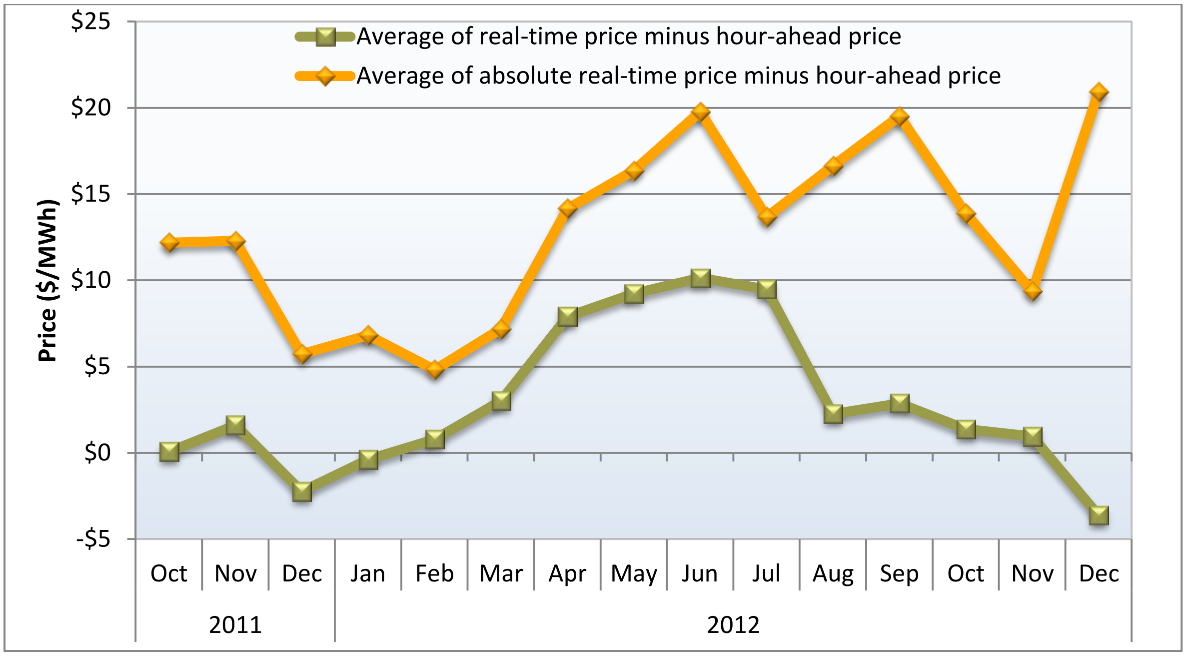
Also shown in Figure 1.4, the average absolute price difference in the hour-ahead and real-time markets shows that price divergence remained at about the same level in the fourth quarter as in the third quarter, averaging about $15/MWh in both quarters and peaking at over $20/MWh in December (yellow line in Figure 1.4). The December absolute difference was the largest since July 2011.[7]

Figure 1.3 Hourly comparison of system marginal energy prices (October – December)



[7] By taking the absolute value, the direction of the difference is eliminated, leaving only the magnitude of the difference. 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)



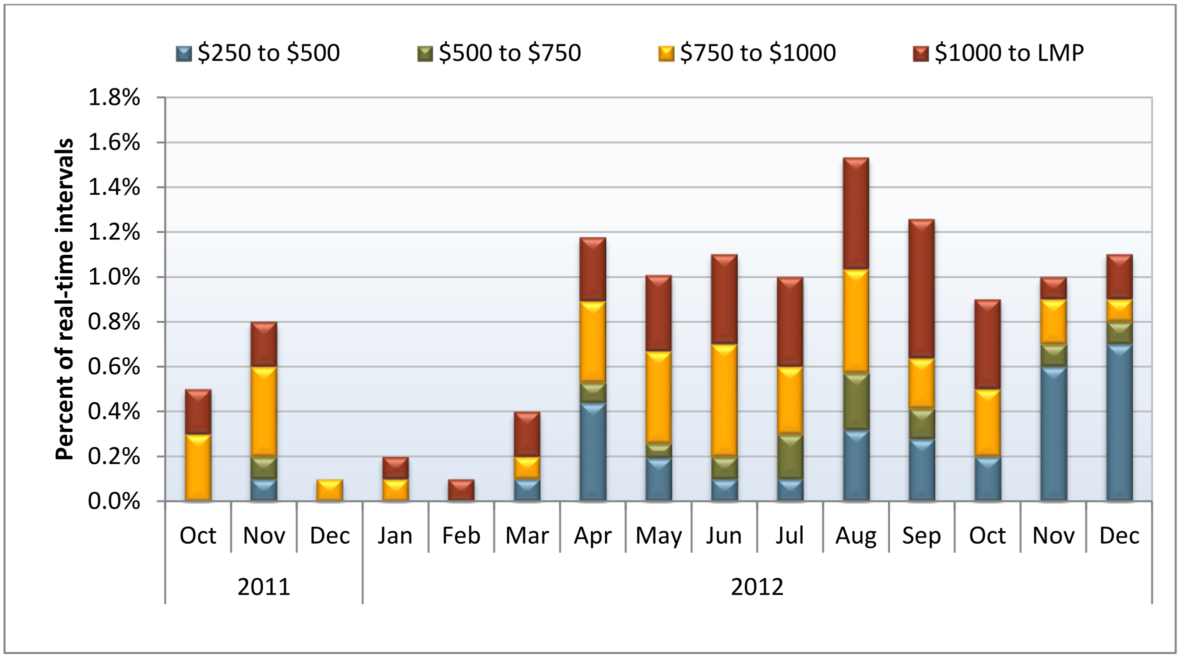
1.2 Real-time price variability

Real-time market prices have historically been variable. This is highlighted in this section along with reasons why the variability occurs.

Figure 1.5 shows a slight decrease in the frequency of price spikes that occur in each investor-owned utility area in the real-time market in the fourth quarter, from an average of 1.3 percent in the third quarter to about 1.0 percent in the fourth quarter. More interestingly, Figure 1.5 shows that the level of price spikes decreased significantly in the fourth quarter, with fewer instances of prices approaching or over the bid cap of $1,000/MWh. This appears to be due to the increase in flexible ramp requirements during the evening ramping hours in November and December. Furthermore, the ISO implemented a new tool in early December that limits the ability of load adjustments made by the ISO operators to create market infeasibilities.

Even though there were improvements in the price variability, 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. Overall, power balance constraint relaxations were lower compared to previous quarters. Figure 1.6 and Figure 1.7 show how often the power balance constraint was relaxed in the 5-minute real-time market software since the fourth quarter of 2011. Figure 1.8 breaks down the factors that contributed to high real-time prices.

Figure 1.5 Frequency of price spikes (all LAP areas)



Relaxations because of insufficient upward ramping capacity were generally lower than the previous quarter, as seen in Figure 1.6. The constraint relaxations were dispersed over different hours of the day but were slightly more common during the evening peak ramp period between hour ending 16 and hour ending 19. Limited ramping capacity and congestion appear to have contributed to the number of upward ramping limitations. Similar to the third quarter, extreme congestion played a key role in numerous instances of power balance constraint relaxations in the fourth quarter.

Power balance relaxations can occur in the presence of congestion. In 2012, around 54 percent of the upward ramping capacity relaxations shown in Figure 1.6 resulted from extreme local congestion. In these cases, the system-wide power balance is not affected; however, the local power balance within the constrained area is affected. When these upward ramping limitations occur, the local constraint is set by a penalty parameter equal to the bid cap of $1,000/MWh.

There was a significant decrease in the number of real-time power balance constraint relaxations from insufficiencies of dispatchable decremental energy in the fourth quarter relative to the third quarter, as shown in Figure 1.7.[8] Seasonal outages lowered the number of instances where over-generation occurred in the market. Almost all of these constraint relaxations resulted from system-wide over-generation conditions.

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

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

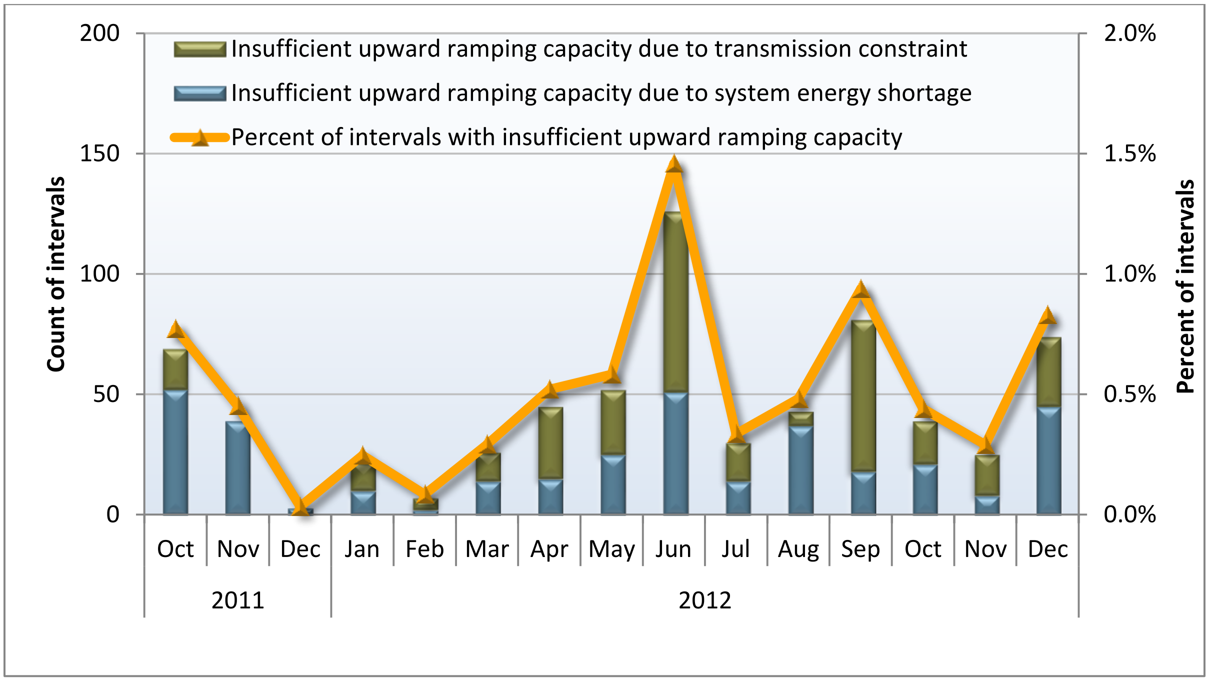


Figure 1.7 Relaxation of power balance constraint because of insufficient downward ramping capacity

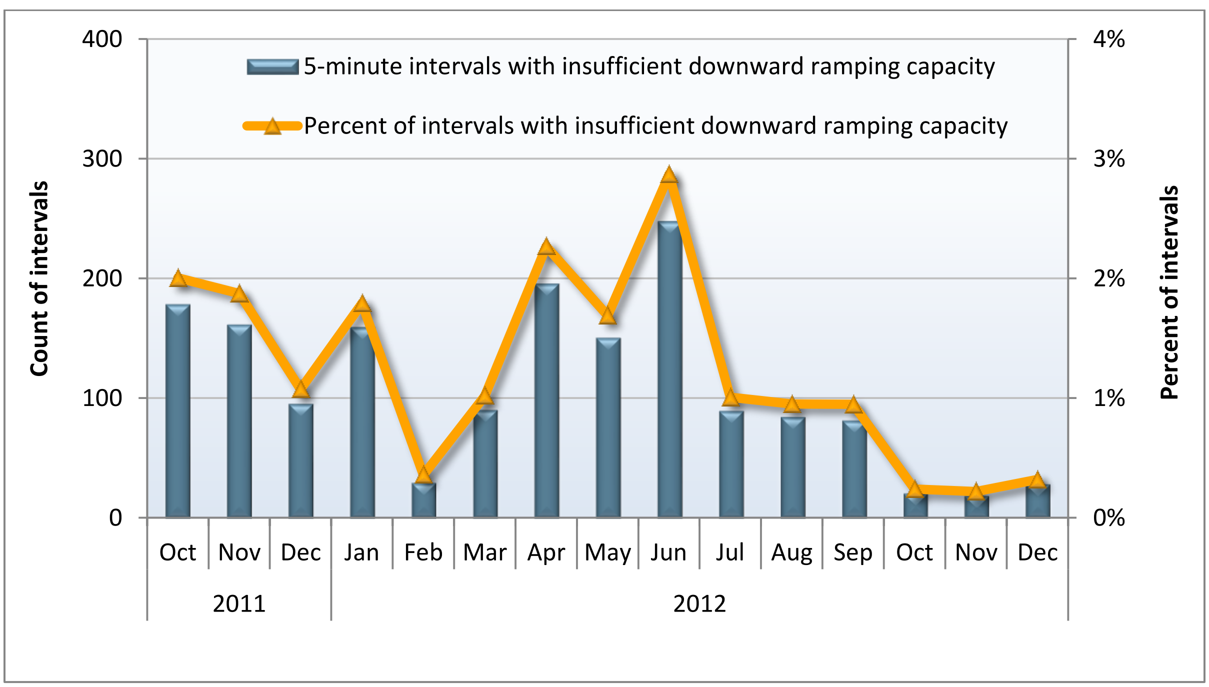
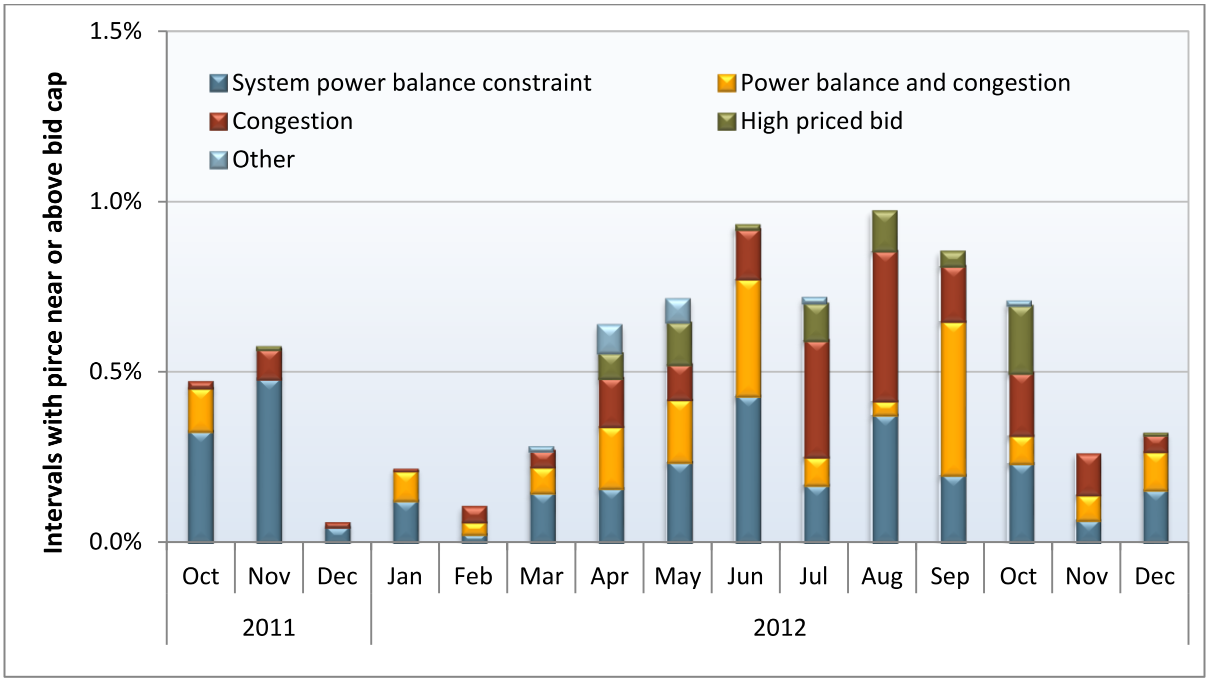


Figure 1.8 Factors causing high real-time prices



Around 56 percent of the extremely high prices were caused by power balance constraint relaxations or a combination of power balance constraint relaxations and congestion in the fourth quarter. Extreme prices from the high priced bids decreased significantly in November and December. Figure 1.8 highlights the different factors driving high real-time prices. The prices in 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 fourth quarter affected overall prices less in the day-ahead and real-time markets than in the third quarter. However, overall, congestion continued to have a significant impact on the market. Much of the congestion was related to unscheduled flows on the California-Oregon Intertie (COI), operation of new lines and the outages of the San Onofre Nuclear Generating Station units 2 and 3, Devers to Valley 500 kV line and the Los Banos to Midway 500 kV#2 line, in conjunction with 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. This is the inverse of congestion in Northern California. The price impacts on individual constraints can differ between the day-ahead and real-time markets, as seen in the following sections.

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

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 price impact, than in the real-time market. Table 1.1 provides information related to the frequency and magnitude of day-ahead market congestion.

The SCE area experienced the greatest frequency of congestion and was affected by the top three most frequently congested constraints.

- Occurring in roughly 38 percent of the hours, the SCE_PCT_IMP_BG was congested more often than any other individual constraint in the quarter. This constraint alone increased the prices in the SCE area by $3.90/MWh in congested hours. The prices in the PG&E and SDG&E areas decreased by about $3.20/MWh. This constraint has been directly affected by the San Onofre outages.

- Congestion on Barre-Lewis_NG, which occurred in about 16 percent of hours, increased prices in the SCE area by $2.25/MWh in congested hours, decreased prices in the PG&E area by $1.86/MWh and increased SDG&E area prices by $1.12/MWh. This constraint was impacted by the San Onofre outages as well as other outages.

- The SLIC 1356092 Serrano Valley OUT constraint was binding in approximately 12 percent of hours. This constraint decreased prices by $0.36/MWh in the SCE area and increased prices in PG&E and SDG&E areas by $0.27/MWh and $0.18/MWh, respectively. However, the related SLIC 1356092 Serrano Valley IN constraint increased prices in the SCE area by $0.57/MWh while decreasing PG&E and SDG&E area prices by $0.64/MWh. These constraints were associated with the outage of the Devers to Valley 500 kV Line in November.

In the SDG&E area, the number of binding constraints increased in the fourth quarter but the percent of binding hours decreased dramatically. Affecting just over 5 percent of hours, the constraint with the highest frequency of congestion in SDG&E was 22342_HDWSH_500_22536_N_GILA_500_BR_1_1. This constraint increased prices in SDG&E area by $9.75/MWh, while decreasing PG&E area prices by $1.60/MWh and SCE by $3.81/MWh. This was a dramatic drop in frequency from the third quarter, where it was congested in nearly 16 percent of hours.

Congestion on Path15_BG was the PG&E area's most congested constraint at just over 9 percent. Congestion on this constraint was associated with an outage on the Los Banos to Midway 500 kV #2 line.

As shown in Table 1.1, congestion on other constraints significantly affected prices during hours when congestion occurred. However, since this internal congestion occurred infrequently, it had a minimal impact on overall day-ahead energy prices.

Table 1.1 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency				Q1			Q2			Q3			Q4		
Area	Constraint	Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	PATH15_BG				9.1%										$1.80	-$1.45	-$1.45
	SLIC 1356082_PVDV-ELDLG_NG				1.6%										$0.52		-$1.44
	SLIC 2040200 Goodrich PVD EM out				1.5%										$0.30		-$1.26
	SLIC 2040200 Goodrich PVD out				2.7%										$0.47		-$2.05
	6110_TM_BNK_FLO_TMS_DLO_NG		6.3%	23.4%					$0.80	-$0.85	-$0.85	$1.80	-$1.51	-$1.51			
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	8.6%				$1.24	-$0.97	-$0.97									
SCE	SCE_PCT_IMP_BG	4.6%	35.6%	24.3%	38.0%	-$1.31	$1.62	-$1.31	-$2.87	$3.40	-$2.87	-$2.15	$2.43	-$2.13	-$3.21	$3.90	-$3.17
	BARRE-LEWIS_NG			5.7%	15.7%							-$0.54	$0.61	$0.37	-$1.86	$2.25	$1.12
	SLIC 1356092 Serrano Valley OUT				11.5%										$0.27	-$0.36	$0.18
	SLIC 1356092 Serrano Valley IN				1.5%										-$0.64	$0.57	-$0.64
	24138_SERRANO _500_24151_VALLEYSC_500_BR_1 _1				1.0%										$5.81	-$9.43	$5.81
	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1				0.5%										$1.70	-$2.60	-$2.60
	24137_SERRANO _230_24154_VILLA PK_230_BR_1 _1				0.4%										-$6.88	$6.78	
	PATH26_BG	4.8%	3.6%	0.4%	0.2%	-$1.63	$1.39	$1.39	-$1.41	$1.16	$1.16	-$3.05	$1.80	$1.80	-$4.80	$3.80	$3.80
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2		0.7%	11.3%					-$3.22	$2.39	$2.44	-$5.24	$3.47	$3.57			
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2			0.7%								-$4.00	$2.37	$2.28			
	SLIC1852244PATH26LIOSN2S	4.7%				-$1.98	$1.66	$1.66									
	SLIC1883001 MIGUEL BKS	1.4%				-$0.14		$5.01									
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.0%				-$1.15	$1.65	-$1.93									
	SLIC 1848345_23021_Outage	0.5%				-$1.17		$7.79									
SDG&E	22342_HDWSH _500_22536_N.GILA _500_BR_1 _1			15.9%	5.3%							-$1.47	-$0.34	$9.20	-$1.60	-$3.81	$9.75
	SLIC 2023497 TL50003_CFERAS				4.3%												$18.08
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80				4.8%												$0.54
	SLIC 1956086_ELD-MCCUL HDW				4.3%										$0.16	-$0.28	$0.46
	IVALLYBANK_XFBG				3.3%												$0.74
	SOUTHLUGO_RV_BG				2.6%										-$3.69	$2.36	$3.94
	7830_SXCYN_CHILLS_NG			23.3%	2.4%									$7.43	-$48.17		$44.23
	SDGE_PCT_UF_IMP_BG		1.1%	0.4%	1.3%				-$0.40	-$0.40	$4.27	-$0.47	-$0.47	$4.70	-$0.55	-$0.55	$5.19
	SLIC 2020109 IV500 SBUS_NG				1.2%										-$0.36		$3.68
	22831_SYCAMORE_138_22116_CARLTHTP_138_BR_1 _1				1.1%												$9.74
	SDGE_CFEIMP_BG	9.0%	2.4%		1.0%	-$0.45	-$0.45	$4.19	-$0.56	-$0.56	$5.64				-$0.88	-$0.88	$7.84
	SLIC 2023497 TL50003_CFERAS_DAM				0.8%												$6.03
	SLIC 2040601 TL23050_NG				0.7%												$3.18
	SLIC 2040600 TL23050_NG				0.5%												$11.57
	22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1				0.5%										-$1.55		$10.99
	SLIC 2040598 TL23050_NG				0.4%												$9.69
	SLIC 2046458 TL23050_NG				0.4%												$4.71
	SDGEIMP_BG			4.4%								-$0.71	-$0.71	$7.19			
	SOUTHLUGO_RV_BG			3.6%								-$9.02	$5.25	$8.15			
	14013_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.4%								-$0.40		$2.91			
	22831_SYCAMORE_138_22116_CARLTHTP_138_BR_1 _1			0.4%										$9.93			
	SLIC 2034755 TL23040_NG			0.6%										$7.36			
	SLIC 1883001_SDGE_OC_NG	14.2%	31.7%			-$0.65	-$0.06	$6.27	-$0.71	$0.28	$6.46						
	SLIC 1883001 Miguel_BKS_NG_2	2.4%	0.9%			-$0.07		$3.08	-$0.45		$6.79						
	SLIC 1977036 Barre-Ellis NG		0.5%						-$0.75		$6.90						
	22832_SYCAMORE_230_22828_SYCAMORE_69.0_XF_2	0.1%						$24.09									

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 on more constraints and with a larger price effect in the intervals when it occurs. Table 1.2 shows the frequency and magnitude of congestion in the fourth quarter.

The SCE area was affected by congestion on four out of the top five most frequently congested constraints in the fourth quarter.

- The top constraint, SLIC 1356092 Serrano Valley OUT constraint, was binding in approximately 11 percent of hours. This constraint decreased prices by $1.43/MWh in the SCE area and increased prices in the PG&E and SDG&E areas by $0.78/MWh. The other direction of this constraint was SLIC 1356092 Serrano Valley IN, the third most congested constraint, at nearly 4 percent, which increased prices in the SCE area by $0.34/MWh and decreased the PG&E and SDG&E area prices by $0.21/MWh. These constraints were associated with a planned outage of the Devers to Valley 500 kV Line in November.
- With just over 6 percent of the hours congested, the SCE_PCT_IMP_BG was the second most congested constraint in the quarter. This constraint alone increased the prices in the SCE area by $44.37/MWh in congested hours, while prices in the PG&E and SDG&E areas decreased by about $35/MWh during these periods. This constraint was directly affected by the San Onofre outages.
- Congestion on Barre-Lewis_NG, which occurred in about 4 percent of hours, increased prices in the SCE area by $8.66/MWh in congested hours and decreased prices in the PG&E and SDG&E areas by about $13.19/MWh and $1.93/MWh respectively. This constraint was also affected by the San Onofre outages.

Prices in the San Diego area were affected by multiple constraints. The SLIC 2023497 TL50003_CFERAS constraint was congested in over 4 percent of the intervals, increasing prices by $59.76/MWh in the SDG&E area and with negligible impact on the SCE and PG&E areas. Occurring in only 0.2 percent of the intervals, the SDGE_CFEIMP_BG had the greatest price impact at $517.89/MWh, while decreasing PG&E and SCE prices by $57.41/MWh. This congestion was mainly due to an outage on the Imperial Valley to Suncrest substation.

Pacific Gas and Electric area prices were most influenced by south-to-north congestion on Path 15 (3.5 percent). The Path15_S-N constraint increased prices in the PG&E area by $26.15/MWh and decreased both the SCE and SDG&E area prices by $21.81/MWh. Congestion on the Path15_S-N constraint was associated with an outage on the Los Banos to Midway 500 kV #2 line.

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 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 38 percent of the hours in the day-ahead market compared to about 6 percent of intervals in the real-time market. While the constraint increased day-ahead prices in the SCE area by nearly $4/MWh, it increased prices by over $44/MWh in the real-time market. For constraints related to the Devers to Valley 500 kV outage, the frequency of congested hours was similar in both markets, but the price impact was about four times greater in the real-time market.

Table 1.2 Impact of congestion on real-time prices by load aggregation point in congested intervals

		Frequency				Q1			Q2			Q3			Q4		
Area	Constraint	Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	PATH15_S-N		0.1%		3.5%				$59.14	-$50.27	-$50.27				$26.15	-$21.81	-$21.81
	SLIC 2042305 ELD-LUGO PVDV				1.6%										$17.75	-$9.26	-$32.63
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1				0.3%										$2.53	-$2.47	-$2.47
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1				0.2%										$52.24	-$36.93	-$92.17
	SLIC 2040200 Goodrich PVD EM out				0.1%										$10.33		-$39.71
	SLIC 2040200 Goodrich PVD out				0.1%										$13.89		-$63.87
	SLIC 1956086_ELD-MCCUL EL-LU				0.1%										$7.21		-$15.37
	SLIC 2041811 PNOCHE-KERNEY SOL1				0.1%										$16.95	-$11.07	-$11.07
	SLIC 1356082_PVDV-ELDLG_NG				0.1%										$9.18		-$23.17
	SLIC 2077489 SOL3				0.1%										$17.62		-$25.95
	30630_NEWARK _230_30703_RAVENSWD_230_BR_1 _1				0.1%											-$32.00	-$32.00
	SLIC 1953261 ELD-LUGO PVDV				0.1%										$64.76	-$28.61	-$126.57
	6110_TM_BNK_FLO_TMS_DLO_NG		1.7%	4.9%					$20.04	-$25.77	-$25.77	$28.95	-$27.11	-$27.11			
	T-135 VICTVLUGO_EDLG_NG			1.8%								$13.62	-$8.51	-$18.09			
	30055_GATES1 _500_30900_GATES _230_XF_11_P			0.3%								$3.63	-$3.04	-$3.04			
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2			1.3%								-$69.86	$46.78	$48.06			
	TRACY230_BG			0.1%								$33.26	-$21.89	-$21.89			
	SLIC 1902749 ELDORADO_LUGO-1	1.1%	1.7%			$3.30	-$2.36	-$3.96	$12.43	-$8.32	-$14.48						
	LBN_S-N	0.02%	0.5%			$1.59	-$1.29	-$1.29	$228.26	-$199.05	-$199.05						
	LOSBANOSNORTH_BG	0.0%	0.1%			$3.22	-$2.74	-$2.74	$179.78	-$142.40	-$142.40						
	SLIC 1977990 SYL_PAR_NG		0.03%						$26.58	-$20.03	-$98.65						
	PATH26_S-N	0.3%	0.02%			$30.46	-$25.84	-$25.84	$1.63	-$1.41	-$1.41						
	SLIC 1902748 ELDORADO_LUGO-1	1.1%				$4.29	-$2.98	-$6.43									
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	3.2%				$4.76	-$3.65	-$3.65									
SCE	SLIC 1356092 Serrano Valley OUT				11.0%										$0.78	-$1.43	$0.78
	SCE_PCT_IMP_BG	0.2%	2.2%	4.4%	6.1%	-$63.37	$79.72	-$63.37	-$69.78	$86.32	-$69.66	-$24.70	$27.25	-$23.63	-$36.29	$44.37	-$35.85
	SLIC 1356092 Serrano Valley IN				4.1%										-$0.21	$0.34	-$0.21
	BARRE-LEWIS_NG			1.7%	3.8%							-$7.84	$5.16	$190.44	-$13.19	$8.66	-$1.93
	24137_SERRANO _230_24154_VILLA PK_230_BR_1 _1				0.4%										-$19.36	$15.09	-$18.45
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1				0.1%										-$25.97	$23.66	
	P26_NS_LOWLIMIT				0.03%										-$192.09	$156.75	$156.75
	PATH26_N-S	2.8%	2.1%	0.2%		-$17.37	$14.65	$14.65	-$59.99	$48.95	$48.95	-$51.51	$33.76	$33.76			
	PATH15_N-S		1.7%						-$38.79	$29.03	$29.03						
	SLIC-1832324-SOL7		0.7%						-$26.50	$17.82	$17.82						
	SLIC 1832324_SOL7_REV1		0.4%						-$8.11	$5.52	$5.52						
	7680 Sylmar_1_NG	0.1%	0.1%					-$60.31	-$11.98	$6.19	-$29.41						
	PATH26_BG		0.1%						-$66.41	$50.25	$50.25						
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	0.02%	0.1%			-$18.58	$22.52	-$70.75	-$10.86	$9.51	-$45.44						
SDG&E	SLIC 2023497 TL50003_CFERAS				4.4%												$59.76
	IVALLYBANK_XFBG				2.0%												$1.53
	22342_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.3%	0.9%							-$47.85		$311.05	-$17.60		$107.78
	SLIC 2020108 IV500 NBUS_NG				0.8%												$10.59
	7830_SXCYN_CHILLS_NG			2.4%	0.6%									$37.61			$14.13
	7820_TL 230S_OVERLOAD_NG	0.2%	1.1%	0.2%	0.5%			$3.64			$50.51			$146.81			$40.48
	SLIC 1956086_ELD-MCCUL HDW				0.5%										$9.50		$20.16
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80				0.4%												$4.91
	SLIC 2020109 IV500 SBUS_NG				0.3%												$14.50
	SLIC 2049607 TL23050_NG_2				0.3%												$7.42
	SLIC 2023351 TL50002_PV				0.3%											-$11.59	$22.70
	SDGE_PCT_UF_IMP_BG				0.2%										-$6.88	-$6.88	$68.79
	SDGE_CFEIMP_BG	0.7%	0.1%		0.2%	-$3.91	-$3.91	$36.83	-$5.16	-$5.16	$54.25				-$57.41	-$57.41	$517.89
	SLIC 2041286 TL50003_NG				0.2%										-$3.37		$22.36
	SOUTHLUGO_RV_BG	0.1%	0.05%	0.5%	0.1%	-$74.07	$59.77	$80.34	-$5.40	$3.82	$6.26	-$192.73	$125.29	$177.63	-$107.67	$77.25	$97.26
	SCIT_BG			0.8%	0.1%							-$77.70	$50.96	$55.22	-$208.38	$142.81	$154.42
	14013_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.3%								-$32.03		$231.77			
	SLIC 2034755 TL23040_NG			0.4%										$38.15			
	SLIC 1953261 ELD-LUGO PVDV			0.3%								$34.59	-$20.15	-$67.32			
	SDGE IMPORTS			0.2%								-$68.23	-$68.23	$646.45			
	HASYAMPA-NGILA-NG1		0.1%	0.2%					-$20.22		$141.43	-$27.71		$227.22			
	22844_TALEGA _230_22840_TALEGA _138_XF_1			0.1%										$78.25			
	SLIC 1883001_SDGE_OC_NG	5.3%	2.7%			-$2.64	-$0.08	$24.17	-$8.17		$68.55						
	SLIC 1884984 Gould-Sylmar		0.5%								-$57.35						
	230S overload for loss of PV		0.5%								-$51.27						
	SDGEIMP_BG		0.1%						-$17.03	-$17.03	$172.81						
	SLIC 1883001 Miguel_BKS_NG_2	1.2%	0.02%					$14.54			$3.77						
	SLIC1852244PATH26LIOSN2S	2.8%				-$7.22	$6.02	$6.02									
	SLIC1883001 MIGUEL BKS	1.4%						$20.10									
	SLIC 1883001 Miguel_BKS_NG	1.0%						$14.23									
	SOUTHEAST_IMPORTS	1.0%						$8.73									
	SLIC 1846936_23021_Outage	0.4%				-$1.78		$12.45									
	SLIC 1908221_22_23028-9_NG	0.2%						-$33.54									

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 fourth quarter of 2012 by constraint. The results show the following:

- The SCE_PCT_IMP_BG increased day-ahead prices in the SCE area above system average prices by $1.48/MWh or almost 4 percent, up from $0.59/MWh (1.7 percent) in the third quarter. Prices decreased by about $1.21/MWh (over 3 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. Additionally, the Barre-Lewis_NG increased the SCE and SDG&E area prices $0.35/MWh (0.94 percent) and $0.07 (0.17 percent) respectively, while decreasing prices in the PG&E area by $0.29 (0.82 percent). This constraint was affected by planned and forced outages.

- As with the third quarter, the day-ahead prices in the San Diego area were impacted the most by internal congestion associated with 7830_SXCYN_CHILLS_NG. This constraint increased day-ahead prices in the SDG&E area by $1.06/MWh or around 2.8 percent, down from $1.73/MWh or around 4.5 percent in the previous quarter. This had negligible impact on the SCE area prices and decreased the PG&E area prices by $0.11/MWh. This constraint protects the system for the potential loss of the Imperial Valley to Miguel 500 kV line. Additionally, the day-ahead prices in the San Diego area were impacted by the SLIC 2023497 TL50003_CFERAS constraint. This constraint increased the prices by $0.79/MWh or around 2 percent.

- The overall impact of congestion on day-ahead prices in the PG&E area decreased prices by about $1.41/MWh or about 4 percent from the system average. This occurred because prices in the PG&E area were lower when congestion occurs on the constraints limiting flows into the SCE and SDG&E areas.

[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.

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	-$1.22	-3.43%	$1.48	3.92%	-$1.21	-3.17%
7830_SXCYN_CHILLS_NG	-$0.11	-0.31%			$1.06	2.79%
SLIC 2023497 TL50003_CFERAS					$0.79	2.07%
BARRE-LEWIS_NG	-$0.29	-0.82%	$0.35	0.94%	$0.07	0.17%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.09	-0.24%	-$0.01	-0.02%	$0.52	1.36%
PATH15_BG	$0.17	0.46%	-$0.13	-0.35%	-$0.13	-0.35%
SOUTHLUGO_RV_BG	-$0.10	-0.27%	$0.06	0.16%	$0.10	0.27%
24138_SERRANO _500_24151_VALLEYSC_500_BR_1 _1	$0.06	0.17%	-$0.10	-0.26%	$0.06	0.16%
22831_SYCAMORE_138_22116_CARLTHTP_138_BR_1 _1					$0.11	0.28%
SDGE_CFEIMP_BG	-$0.01	-0.02%	-$0.01	-0.02%	$0.08	0.21%
SLIC 1356092 Serrano Valley OUT	$0.03	0.08%	-$0.04	-0.11%	$0.02	0.05%
SDGE_PCT_UF_IMP_BG	-$0.01	-0.02%	-$0.01	-0.02%	$0.07	0.17%
SLIC 2040200 Goodrich PVD out	$0.01	0.04%			-$0.06	-0.14%
22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1	-$0.01	-0.02%			$0.05	0.13%
SLIC 2040600 TL23050_NG					$0.05	0.14%
24137_SERRANO _230_24154_VILLA PK_230_BR_1 _1	-$0.03	-0.07%	$0.03	0.06%		
SLIC 2023497 TL50003_CFERAS_DAM					$0.05	0.13%
SLIC 2020109 IV500 SBUS_NG					$0.04	0.11%
SLIC 2040598 TL23050_NG					$0.04	0.10%
SLIC 1356082_PVDV-ELDLG_NG	$0.01	0.02%			-$0.02	-0.06%
SLIC 1956086_ELD-MCCUL HDW	$0.01	0.02%			$0.02	0.05%
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80					$0.03	0.07%
SLIC 2040200 Goodrich PVD EM out	$0.01	0.01%			-$0.02	-0.05%
IVALLYBANK_XFBG					$0.02	0.06%
SLIC 2040601 TL23050_NG					$0.02	0.06%
PATH26_BG	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.02%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
SLIC 2046458 TL23050_NG					$0.02	0.05%
SLIC 1356092 Serrano Valley IN	-$0.01	-0.01%	$0.01	0.02%	-$0.01	-0.01%
SLIC 2040599 TL23050_NG					$0.01	0.03%
22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1					$0.01	0.03%
SLIC 2023351 TL50002_PV				-0.01%	$0.01	0.02%
SLIC 2071849_GDRCH_SYLM-PARD		0.01%		-0.01%	-$0.01	-0.02%
22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1					$0.01	0.03%
33020_MORAGA _115_30550_MORAGA _230_XF_1A_P	$0.01	0.03%				
SLIC 2041833 PNOCHE-KERNEY SOL1		0.01%		-0.01%		-0.01%
30055_GATES1 _500_30900_GATES _230_XF_11_P		0.01%		-0.01%		-0.01%
Other	$0.14	0.40%	$0.16	0.43%	-$0.47	-1.23%
Total	-$1.41	-4.0%	$1.79	4.7%	$1.34	3.5%

Real-time price impacts

Table 1.4 shows the overall impact of real-time congestion on average prices in each load area in the fourth quarter of 2012 by constraint. These results show the following:

- Congestion drove prices in the SCE area above system average prices by about $2.26/MWh or 5.8 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 by about $0.77/MWh (2 percent).

- Prices in the San Diego area were impacted the most by internal congestion associated with the SLIC 2023497 TL50003_CFERAS, SDGE_CFEIMP_BG and 22342_HDWSH_500_22536_N.GILA_500_BR_1_1 constraints. Combined, these constraints drove prices above the system average in the SDG&E area by nearly 12 percent or about $4.65/MWh. While these constraints drove SDG&E congestion up, congestion in the SCE area drove the SDG&E area prices down (e.g., SCE_PCT_IMP_BG). Together, the positive and negative congestion caused average real-time prices in the San Diego area to increase by about $1.97/MWh or about 5 percent above the system average.
- The overall impact of congestion on prices in the PG&E area was to change prices from the system average by about -$2.09/MWh or about -6 percent. This happens because 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., P26_NS_LOWLIMIT) 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 associated with an outage on the Los Banos to Midway 500 kV #2 line. This constraint increased prices in the PG&E area over $0.92/MWh (2.6 percent) during the fourth quarter.

Overall, real-time congestion occurred less frequently than day-ahead congestion, yet its overall price impact 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, and changes made by ISO operators associated with conforming line limits to make market flows reflect actual flows and to provide a reliability margin.

Congestion price differences 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. Congestion was very different over the last several months using both the simple and absolute averages.

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. However, beginning in February 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.

In November 2012, for example, the absolute difference between the day-ahead and the real-time markets in the SDG&E area was just under $15/MWh while the average difference was approximately $5/MWh. Price differences were also significant between the day-ahead and hour-ahead market, as November 2012 SDG&E price differences averaged about $7.30/MWh and $4/MWh for absolute and simple averages, respectively.

Convergence bidders have been able to profit from these differences and real-time imbalance congestion costs, as shown below, have continued as a result. The congestion differences were related to differences in system conditions including outages and line ratings.

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	-$2.22	-6.37%	$2.72	7.04%	-$2.20	-5.72%
SLIC 2023497 TL50003_CFERAS					$2.65	6.88%
PATH15_S-N	$0.92	2.64%	-$0.77	-1.99%	-$0.77	-2.00%
SDGE_CFEIMP_BG	-$0.11	-0.31%	-$0.11	-0.28%	$0.98	2.54%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.16	-0.46%			$0.98	2.56%
SLIC 2042305 ELD-LUGO PVDV	$0.29	0.81%	-$0.14	-0.35%	-$0.52	-1.36%
BARRE-LEWIS_NG	-$0.50	-1.43%	$0.33	0.85%	-$0.01	-0.03%
SCIT_BG	-$0.18	-0.52%	$0.12	0.32%	$0.13	0.35%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.11	0.31%	-$0.08	-0.20%	-$0.19	-0.50%
SOUTHLUGO_RV_BG	-$0.11	-0.31%	$0.08	0.20%	$0.10	0.26%
SLIC 1356092 Serrano Valley OUT	$0.05	0.15%	-$0.16	-0.41%	$0.05	0.14%
7820_TL 230S_OVERLOAD_NG					$0.21	0.55%
SDGE_PCT_UF_IMP_BG	-$0.02	-0.04%	-$0.02	-0.04%	$0.15	0.40%
24137_SERRANO _230_24154_VILLA PK_230_BR_1 _1	-$0.09	-0.25%	$0.07	0.18%	-$0.004	-0.01%
SLIC 1956086_ELD-MCCUL HDW	$0.04	0.10%			$0.10	0.27%
P26_NS_LOWLIMIT	-$0.05	-0.15%	$0.04	0.11%	$0.04	0.11%
SLIC 1953261 ELD-LUGO PVDV	$0.03	0.10%	-$0.02	-0.04%	-$0.07	-0.17%
SLIC 2023351 TL50002_PV			-$0.03	-0.08%	$0.06	0.15%
7830_SXCYN_CHILLS_NG					$0.09	0.22%
SLIC 2020108 IV500 NBUS_NG					$0.08	0.22%
SLIC 2040200 Goodrich PVD out	$0.01	0.04%			-$0.06	-0.16%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.03	-0.08%	$0.03	0.06%		
SLIC 2040200 Goodrich PVD EM out	$0.01	0.02%			-$0.04	-0.10%
SLIC 2020109 IV500 SBUS_NG					$0.04	0.11%
SLIC 2041286 TL50003_NG	-$0.01	-0.02%			$0.04	0.10%
30630_NEWARK _230_30703_RAVENSWD_230_BR_1 _1			-$0.02	-0.05%	-$0.02	-0.05%
SLIC 2041811 PNOCHE-KERNEY SOL1	$0.01	0.04%	-$0.01	-0.02%	-$0.01	-0.02%
IVALLYBANK_XFBG					$0.03	0.08%
SLIC 2077489 SOL3	$0.01	0.03%			-$0.02	-0.04%
SLIC 1356092 Serrano Valley IN	-$0.01	-0.01%	$0.01	0.04%	-$0.01	-0.01%
SLIC 1356082_PVDV-ELDLG_NG	$0.01	0.02%			-$0.02	-0.04%
SLIC 2049607 TL23050_NG_2					$0.02	0.05%
30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80					$0.02	0.05%
SLIC 1956086_ELD-MCCUL EL-LU	$0.01	0.02%			-$0.01	-0.03%
Other	-$0.12	-0.33%	$0.20	0.51%	$0.13	0.35%
Total	-$2.09	-6.0%	$2.26	5.8%	$1.97	5.1%

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

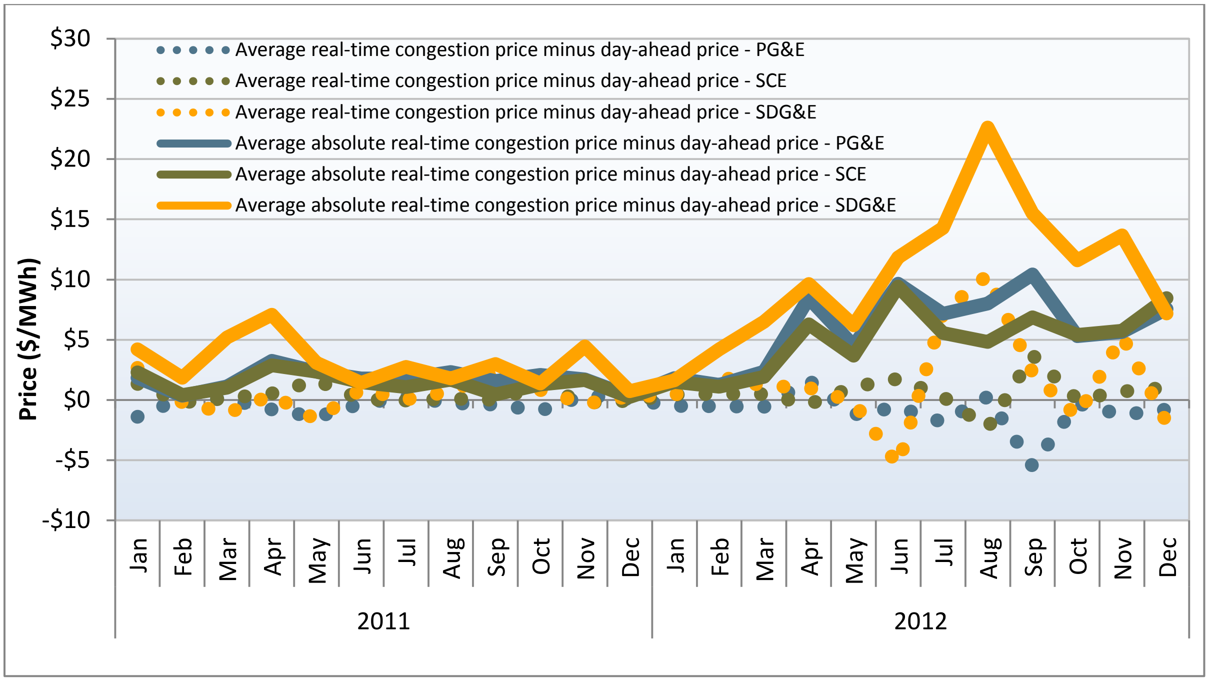
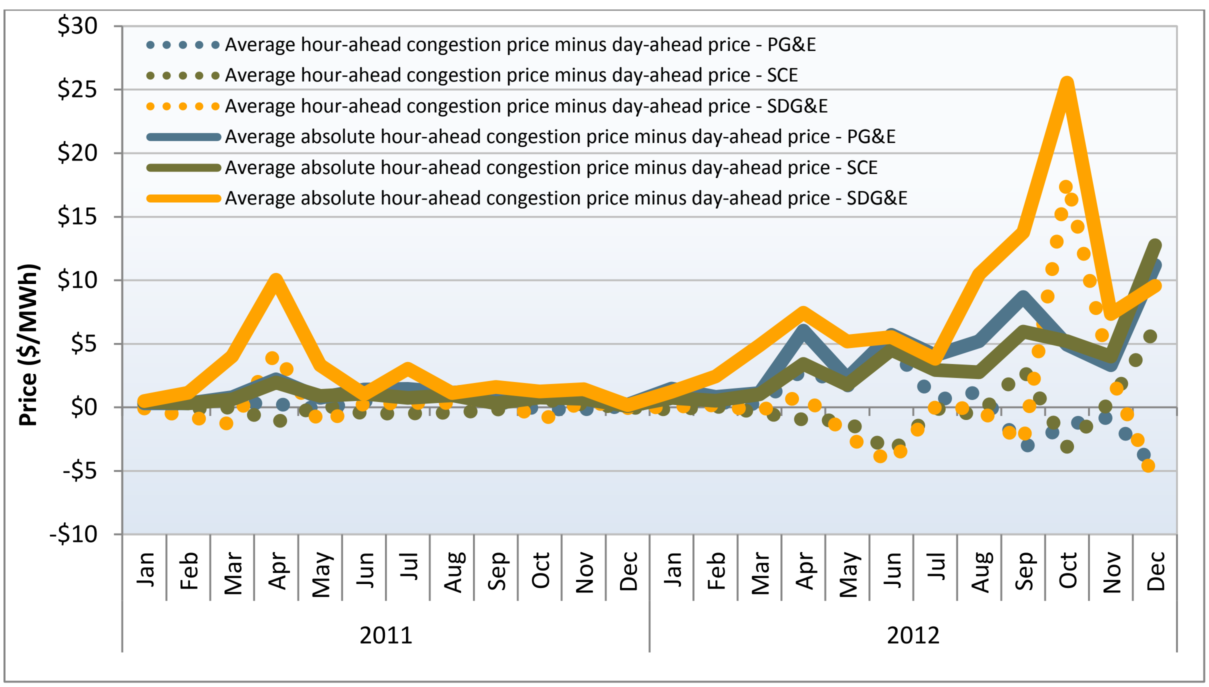


Figure 1.10 Monthly average and absolute congestion price differences between the day-ahead and hour-ahead markets



1.4 Real-time imbalance offset costs

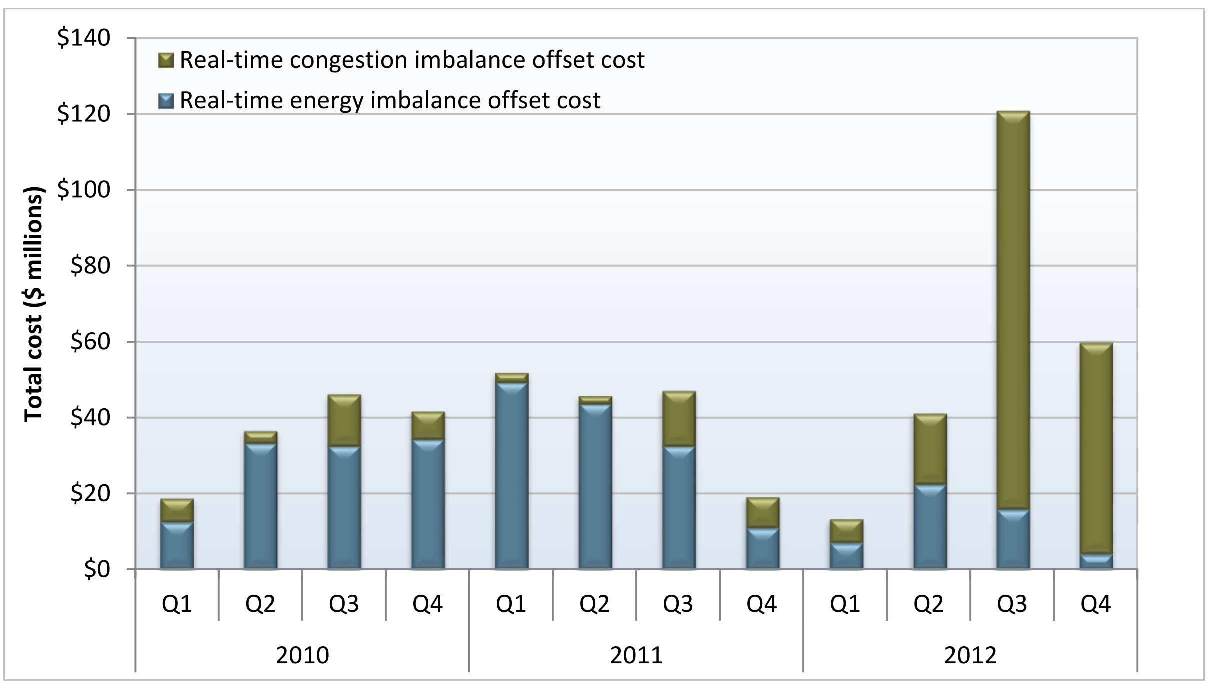
High real-time congestion imbalance offset costs continued in the fourth quarter, while real-time energy imbalance costs remained low. Congestion imbalance costs remained high as systematic differences in congestion occurred between the day-ahead and real-time markets on select constraints. These costs were also influenced by transmission outages as well as line limit conforming by ISO operators.

Real-time congestion imbalance offset costs totaled about $60 million in the fourth quarter (see Figure 1.11) and were almost $28 million in the month of October alone. Energy imbalance uplifts totaled about $4 million in the fourth quarter.

Net congestion payments and charges for virtual demand and supply that liquidated in the real-time market account for about $25 million in real-time congestion imbalance costs in the fourth quarter. However, this excluded the congestion payments made by convergence bidders in the day-ahead market. DMM estimates the net effect of virtual bids by combining the net day-ahead congestion payments by convergence bidding participants with net real-time congestion payments to convergence bidding participants.

Using this method, DMM estimates that convergence bidding accounted for a net effect of almost $16 million in congestion imbalance offset costs in the fourth quarter.[11] For 2012, DMM estimates that convergence bidders paid about $36 million in day-ahead congestion and received $95 million (out of $186 million) in real-time congestion imbalance offset charges for a net payment of $59 million.

Figure 1.11 Real-time imbalance offset costs



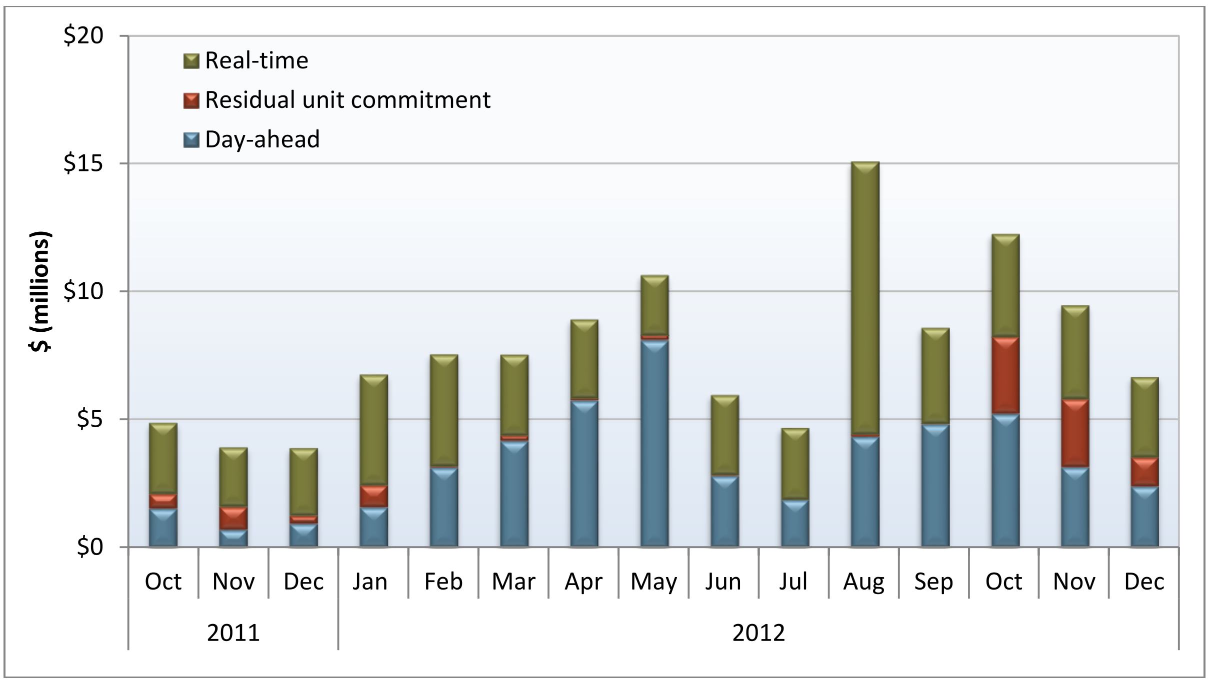
[11] This removes $9 million in congestion charges paid by convergence bidding participants in the day-ahead market from the $25 million in net congestion payments made to convergence bidding participants in the real-time market.

1.5 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.[12] While bid cost recovery payments trended down over the quarter, they were about the same level in aggregate as the previous quarter.

Bid cost recovery payments totaled around $29 million in the fourth quarter, compared to $28 million in the third quarter (see Figure 1.12 for a monthly breakdown). While real-time bid cost recovery payments decreased by 37 percent to $11 million in the fourth quarter from the previous quarter, the residual unit commitment portion of the bid cost recovery payments increased notably. The residual unit commitment payments reached around $7 million in the fourth quarter, compared to $1.6 million in the first nine months of 2012.

Figure 1.12 Monthly bid cost recovery payments



The increase in these payments was related to the outage of the Captain Jack to Olinda 500kV line. This outage reduced the north-to-south transfer capability of the California Oregon Intertie (COI) up to 40 percent. This situation created reliability concerns with having sufficient capability to be able to unload the COI in case of a single contingency in the required 30 minutes in the PG&E area during the peak hours. As a result, ISO operators made adjustments to the regional residual unit commitment requirements to mitigate potential contingencies related to sufficient capacity. The adjustments began in mid-October and continued till mid-November.

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

After evaluating the effectiveness of the regional residual unit commitment adjustments and coincident limitations on Path 15, the ISO decided to replace these adjustments with a new minimum online constraint for the PG&E area.[13] After the addition of the new constraint, residual unit commitment bid cost recovery payments fell. However, some residual unit commitment bid cost recovery payments remained because ISO operators continued to make adjustments to the system residual unit commitment requirements. These changes were concentrated in the late afternoon and early evening hours during the steep ramping period in real time.

Ultimately, both the residual unit commitment process and minimum online constraints are not very effective in meeting specific capability needs. These processes only commit units to their minimum capacity and not to their dispatchable minimum capacity. These processes are designed as capacity and not ramping constraints. As a result, both of these processes have limited abilities to schedule target ramping capability for the real-time market. The ISO is considering a new dynamic approach to resolving transmission constraints that require the ability to reduce flow limits within a required period of time. DMM is supportive of this process to address the recurring need for 30-minute ramping capability.[14]

[13] Minimum online constraints are based on existing operating procedures that require a minimum quantity of online capacity from a specific group of resources in a defined area. These constraints make sure that the system has enough longer start capacity online to meet locational voltage requirements and respond to contingencies that cannot be directly modeled, such as the 30-minute ramping concern with the COI limitation.

[14] More information regarding the new market initiative on post contingency corrective constraints can be found at: http://www.caiso.com/Documents/NewStakeholderInitiativePostContingencyCorrectiveConstraints.htm.

2 Convergence bidding

The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. 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. Virtual bidding on inter-ties was suspended on November 28, 2011.[15] Thus, 2012 represents a full year with virtual bidding within the ISO system but not at the inter-ties.

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.

Virtual bidding participants were paid net revenues of over $15 million in the fourth quarter. Most of these net revenues resulted from virtual bids at offsetting internal locations to take advantage of higher congestion in real-time. Offsetting internal bids represented over 60 percent of all virtual bids in the fourth quarter. The increase in both the quantity and net revenues of offsetting internal virtual bids likely arises from the differences in congestion between the day-ahead and real-time markets (see Section 1.3 for further detail).

Internal virtual supply averaged around 1,380 MW while virtual demand averaged around 1,995 MW each hour during the quarter. Thus, the average hourly net virtual position in the fourth quarter was 600 MW of virtual demand. 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 slightly 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:

- 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.

[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.

Thus, virtual bidding allows participants to profit by arbitraging the 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 in 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.[16] 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.

2.1 Convergence bidding trends

Total hourly trading volumes increased to 3,300 MW in the fourth quarter from 3,100 MW in the third quarter. Also, the share of cleared virtual demand of all virtual positions dropped to 59 percent in the fourth quarter down from 64 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, 50 percent of virtual supply and demand bids offered into the market cleared in the fourth quarter.

- Cleared volumes of virtual demand outweighed cleared virtual supply in the third quarter by around 350 MW on average, down from around 900 MW in the third quarter.

- Virtual demand exceeded virtual supply during peak hours by about 660 MW, while during the off-peak hours virtual supply was greater than virtual demand by 280 MW. In the third quarter, the same trend existed, but the volumes were higher in peak periods and slightly lower in off-peak periods.

[16] 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

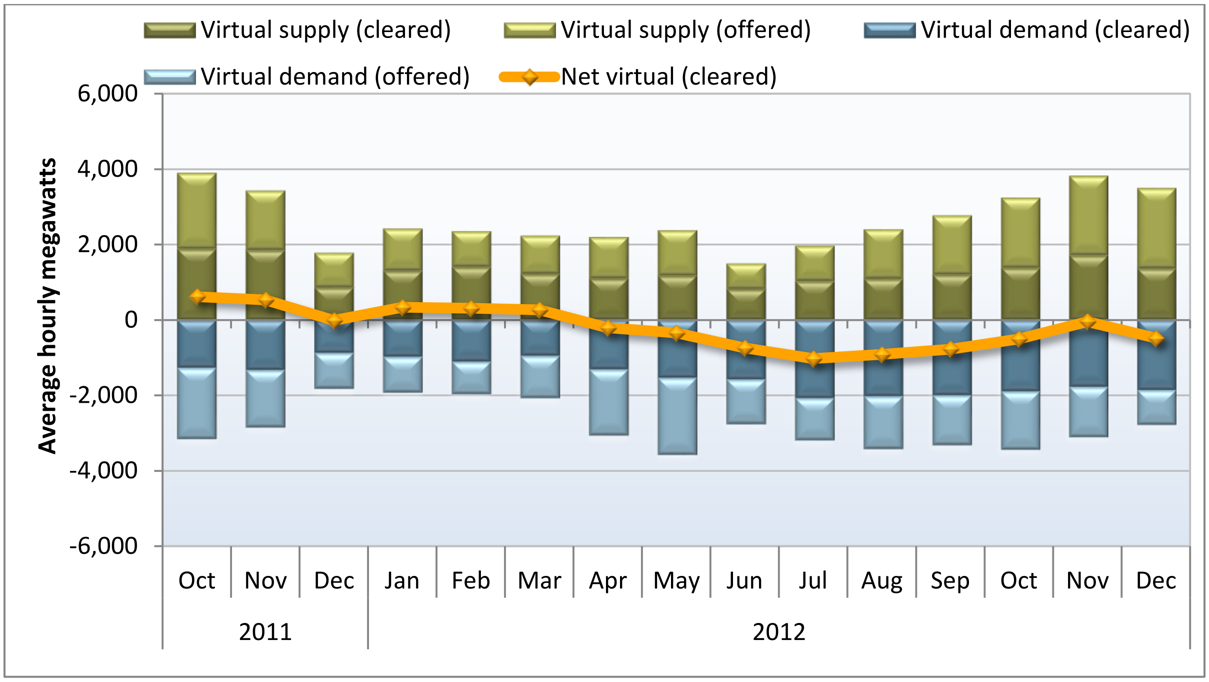


Figure 2.2 Hourly offered and cleared virtual activity (October – December)

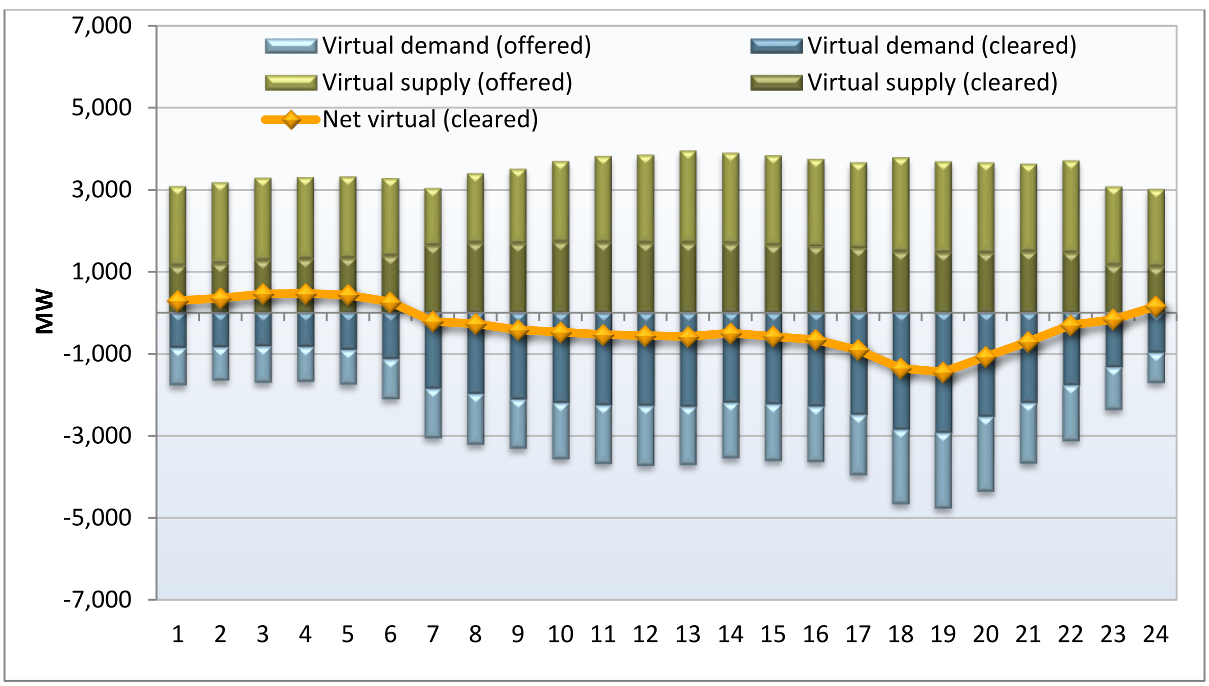
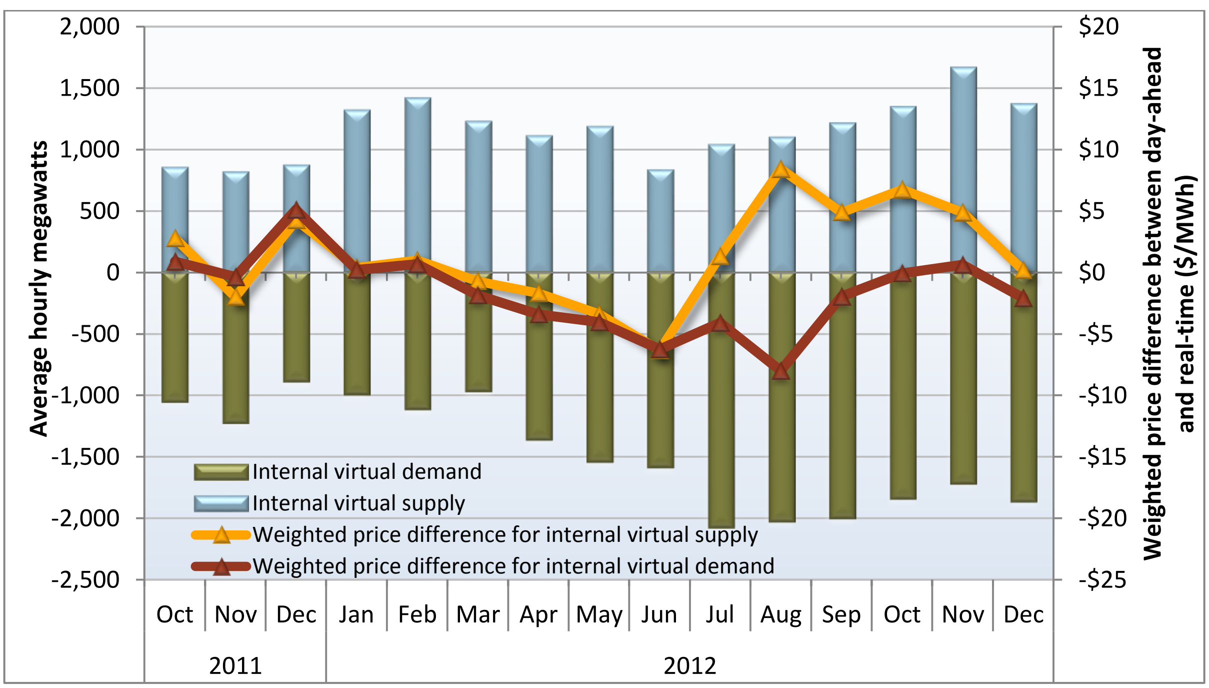


Figure 2.3 compares cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in Figure 2.3 represents the average price difference weighted by the amount of virtual bids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

- Months in which the red line in Figure 2.3 is negative indicates that the weighted average price charged for internal virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand. Internal virtual demand volumes were directionally consistent with weighted average price differences, and therefore profitable, in most months in 2012. The exceptions were January, February and November, where average weighted real-time prices were slightly lower than day-ahead prices.
- Months in which the yellow line in Figure 2.3 is positive 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 virtual supply was liquidated in the real-time market. Virtual supply at internal locations was consistent and profitable with weighted average price differences in the third and fourth quarters.
- As noted later in this section, 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 profiting 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 because of congestion. The share of these bids increased in the fourth quarter.

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



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. Convergence bidding volumes were consistent with price differences in many hours early in 2012. However, beginning in the third quarter and continuing into the fourth quarter, net convergence bidding volumes, on average, were consistent with price differences between the day-ahead and real-time markets in only about half of the hours.

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 October, November and December, 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 received outweigh losses that happened otherwise in every month of the fourth quarter (see Section 2.2 for further detail).

- As shown in Figure 2.4, convergence bidding volumes in October were consistent in about half of the hours with price convergence at internal locations. Consistency was best in the off-peak hours and in the later afternoon hours.
- In November, as seen in Figure 2.5, convergence bidding volumes were also directionally consistent with differences between day-ahead and real-time prices in about half of the hours. The consistency of net cleared convergence bidding volumes with off-peak hourly prices improved while the consistency of volumes with peak prices decreased compared to previous months.
- Figure 2.6 convergence bidding volumes in a majority of hours in December were not consistent with price convergence at internal locations. In total, there were only 10 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 – October

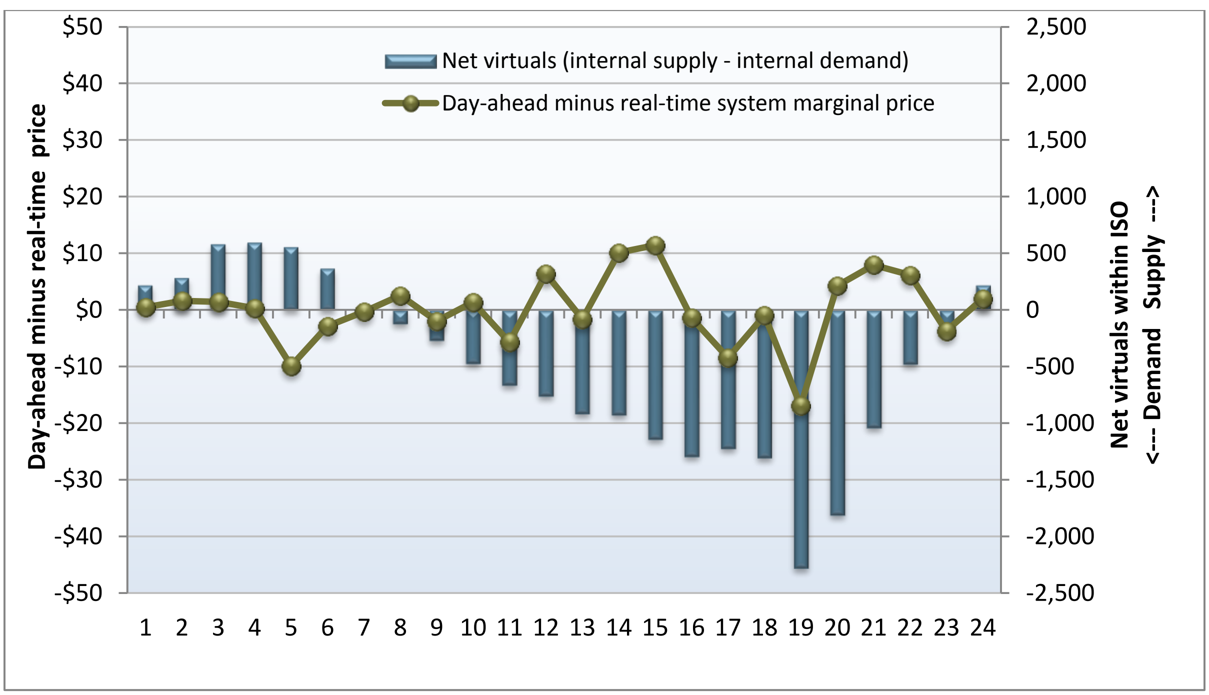


Figure 2.5 Hourly convergence bidding volumes and prices – November

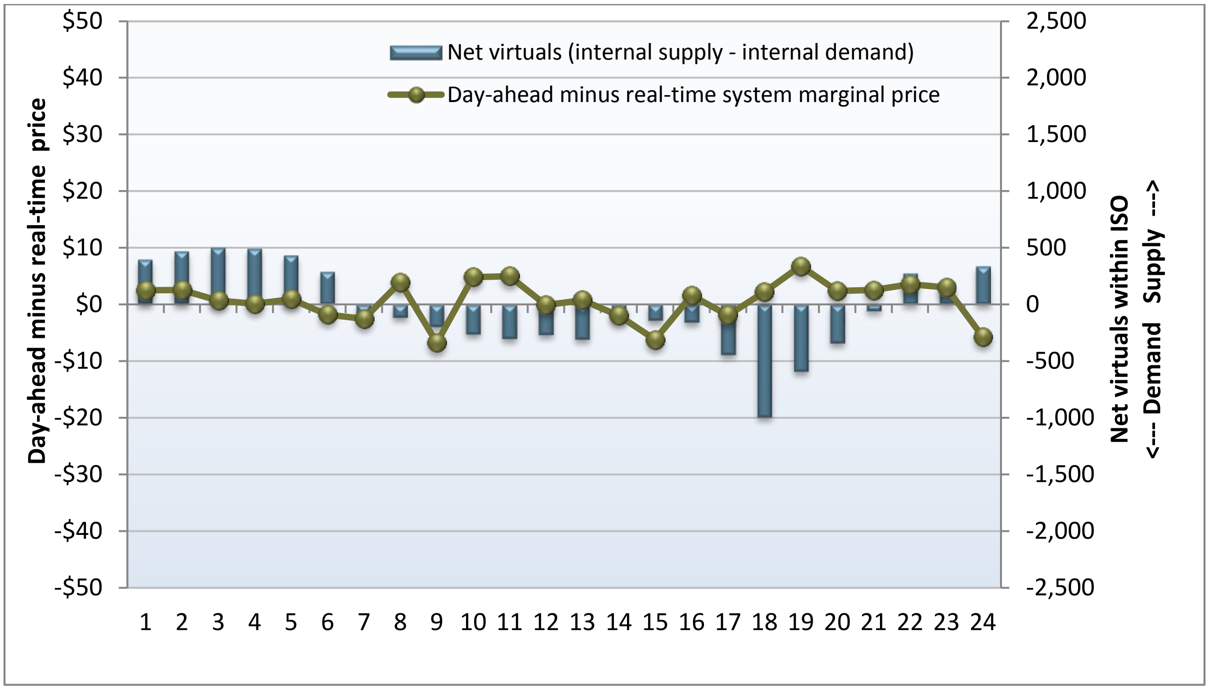
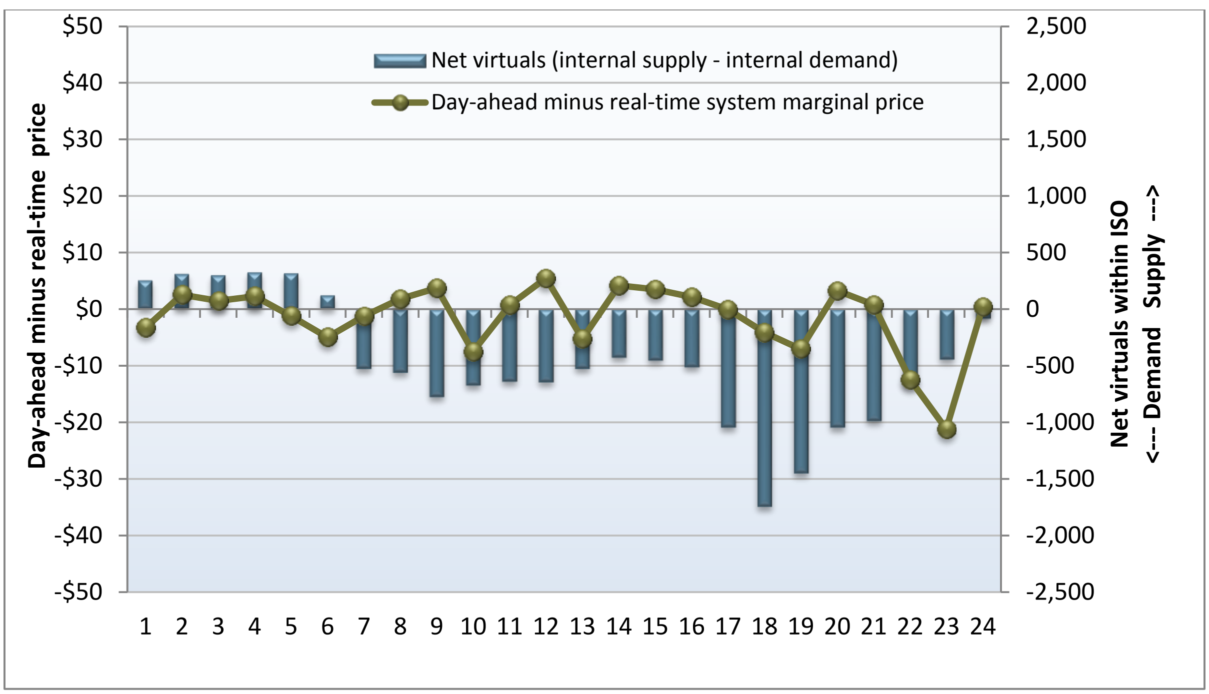


Figure 2.6 Hourly convergence bidding volumes and prices – December



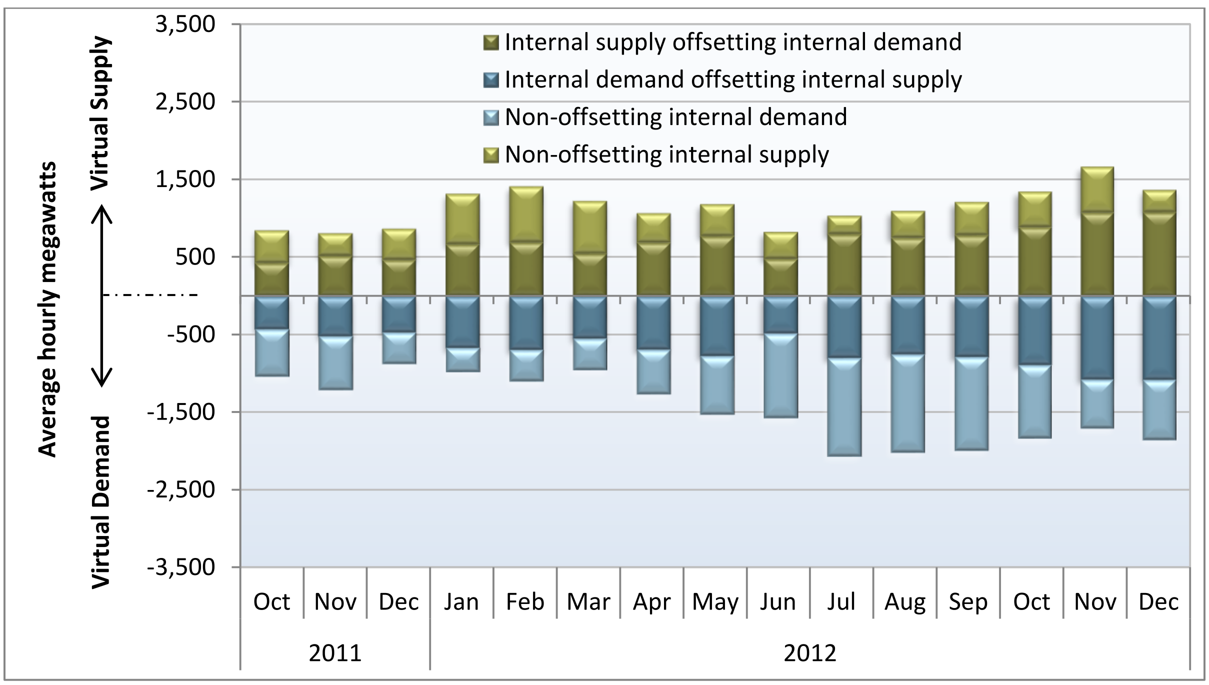
Offsetting virtual supply and demand bids at internal points

Market participants can also hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO by placing virtual demand and supply bids at different internal locations during the same hour.

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 offset between internal demand and internal supply.[17] 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.

As shown in Figure 2.7, this type of offsetting virtual position at internal locations accounted for an average of about 1,014 MW of demand offset by 1,014 MW of virtual supply at other locations in each hour in the fourth quarter. These offsetting bids represent over 60 percent of all cleared internal bids in the fourth quarter, up from 50 percent in the previous quarter. This suggests that since the suspension of virtual bidding on inter-ties, virtual bidding has been increasingly used to hedge or profit from internal congestion.

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



[17] When calculating the offset between each participant's accepted virtual supply and demand bids at internal points each hour, we did not include the portion (if any) of the participant's internal virtual demand bids that were offset by accepted virtual import bids by that participant in the months before virtual bidding at the inter-ties were suspended. This was done to avoid any potential double counting of internal virtual demand as offsetting virtual imports and virtual supply within the ISO during the same hour.

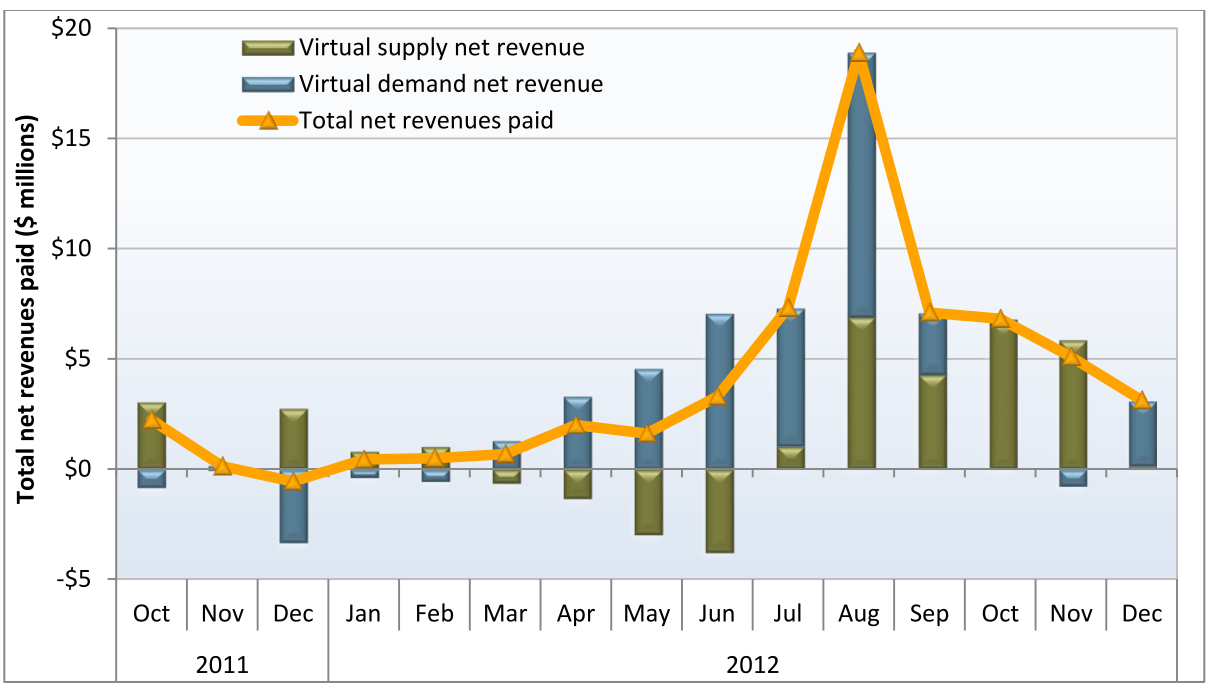
2.2 Convergence bidding payments

This section highlights sources of net revenues received by convergence bidders. In the fourth quarter, net revenues totaled $15 million, with most of these revenues associated with offsetting virtual bids.

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

- Virtual supply revenues increased substantially in the fourth quarter. In October and November, the higher frequency of negative real-time prices accompanied by congestion during off-peak hours contributed to these revenues.
- Virtual demand net revenues were lower in the fourth quarter. In total, virtual demand accounted for approximately $2 million in revenues.
- Total net revenues paid to virtual bidders dropped from the third to the fourth quarter. This change was driven by decreased revenues on virtual demand positions. Revenues on virtual supply positions remained about the same.
- In the fourth quarter, net revenues paid to convergence bidding entities totaled over $15 million. Virtual demand accounted for over $2 million, and virtual supply was about $12 million. As noted above, the virtual supply bids were typically profitable during off-peak hours, while virtual demand was profitable in the peak hours.

Figure 2.8 Total monthly net revenues paid from convergence bidding



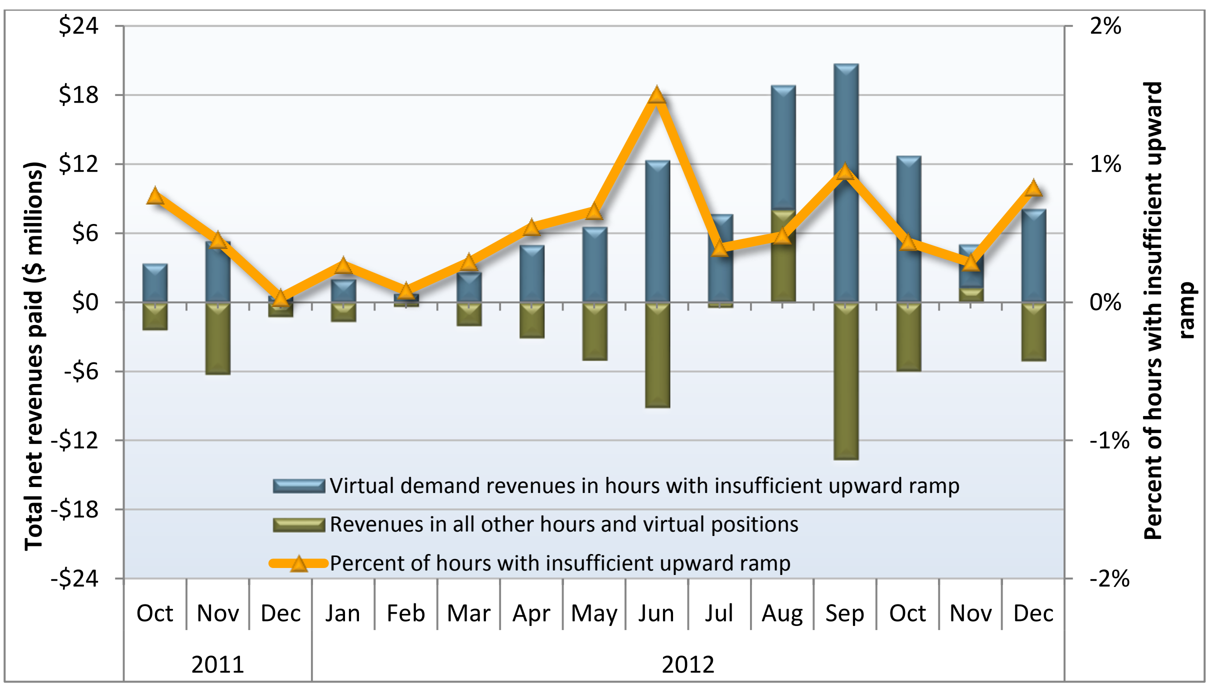
Net revenues at internal scheduling points

In the third quarter, virtual demand accounted for about 64 percent of cleared virtual bids at internal locations; in the fourth quarter it decreased to 59 percent. Virtual demand bids at internal locations are profitable when real-time prices spike in the 5-minute real-time market. Historically, almost all net revenues paid for these 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. This typically occurs during off-peak hours when over-generation drives 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 about 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. Having a single 5-minute interval price spike can yield enough revenue to compensate for losses in the remaining hours of the day.
- As an example, in October, virtual demand net revenues were positive $12 million during intervals with insufficient upward ramp and negative $12 million during all other periods. The net virtual supply position was positive $6 million. Thus, virtual demand positions during intervals with insufficient upward ramp outweighed all other positions by $6 million in October.[18]

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



[18] Revenues in all other hours are equal to both virtual supply and virtual demand revenues outside insufficient ramp intervals.

Price spikes associated with upward ramp insufficiencies are typically associated with brief shortages of ramping capacity and congestion. In theory, virtual demand at internal scheduling points can potentially result in additional capacity being committed and available in the real-time market. In practice, the impact of internal virtual demand on real-time price spikes appears to have been limited by the fact that any additional capacity available to convergence bidding may not be enough to resolve congestion or the short-term ramping limitations. This is further exacerbated by the hour-ahead market, which often does not reflect the same system conditions as in the real-time market and frequently reduces net imports, decreasing the benefits of additional capacity added in the day-ahead 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 money by bidding virtual demand as well as reduces the potential benefits to virtual supply bids at internal nodes.

2.3 Changes in unit commitment

If physical generation resources clearing the day-ahead energy market are less than the ISO forecasted demand, the residual unit commitment ensures that enough additional capacity is available to meet the forecasted demand. Total direct residual unit commitment costs, which are the residual unit commitment clearing price times the non-resource adequacy capacity cleared in each hour, were around $2 million in the fourth quarter, up from $1,600 in the third quarter. Bid cost recovery payments for capacity committed in the residual unit commitment process, which account for start-up and minimum load costs as well as real-time revenues, were around $7 million in the fourth quarter, up from $130,000 in the previous quarter.

The residual unit commitment adds more capacity to meet differences between forecasted and bid-in demand, to offset the loss of virtual supply and to meet additional local reliability needs. DMM has estimated the share of the total residual unit commitment cost that is attributable to virtual supply by reviewing the factors that led to residual unit commitment and comparing the virtual supply as a percentage of the total.

Since the net convergence bidding position was primarily virtual demand in the fourth quarter, convergence bidding did not play a significant role in the cost increases in the fourth quarter. The increase in both the direct capacity payments and bid cost recovery payments were a result of adjustments to the regional residual unit commitment requirements by the ISO operators to mitigate potential contingencies and increase reliability (see Section 1.5).

3 Special issues

This section highlights the performance of the flexible ramping constraint over the last year. While it is difficult to benchmark the performance of the constraint with other products, DMM highlights several performance factors and makes recommendations on how to better understand its effect on the market.

The key factors include the following observations:

- Flexible ramping costs were $3 million in the fourth quarter and $20 million for the year. For the sake of comparison, spinning reserve costs were $10 million in the fourth quarter and about $35 million for the year.
- 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.
- The ISO operators began to increase the flexible ramping requirement more consistently during the evening ramping periods of the day in the fourth quarter.
- Just over half of the flexible ramping capacity was in the northern part of the state, which can be stranded when congestion occurs in the southern part of the state.

DMM continues to recommend that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in real-time.

3.1 Flexible ramping constraint

This section provides background of the flexible ramping constraint, highlights key performance measures, and makes recommendations for further review.

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. Application of the constraint in the 15-minute real-time pre-dispatch market ensures that enough capacity is procured to meet the flexible ramping requirement. The default requirement is currently set to around 300 MW. The ISO operators adjusted the requirement more frequently in the fourth quarter of 2012 to prepare for potential ramping shortages during the evening ramping periods.

The flexible ramping constraint was implemented to account for the non-contingency based variations in supply and demand between the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch. The additional flexible ramping capacity is designed to supplement the existing non-contingent spinning reserves in the system in managing these variations.

The ISO procures the available 15-minute dispatchable capacity from the available set of resources in the 15-minute real-time pre-dispatch run. If there is sufficient capacity already online, 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. The short-start units can be eligible for bid cost recovery payments in real-time.[19] 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.[20]

Performance of the flexible ramping constraint

The total payments for flexible ramping resources in 2012 were around $20 million, with around $3 million occurring in the fourth quarter.[21] For the sake of comparison, costs for spinning reserves have totaled about $35 million in 2012, with around $10 million occurring in the fourth quarter. 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.

Table 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 when the flexible ramping constraint was binding has varied, being highest in the spring (19 percent) and lowest in the fourth quarter (7 percent).
- The frequency of procurement shortfalls fell to around 1 percent of all 15-minute intervals in the fourth quarter, compared to approximately 2 percent in the first nine months.
- The total payments to generators for the flexible ramping constraint were around $3 million, almost the same as the previous quarter.
- The average shadow price that occurred when the flexible ramping constraint was binding increased in November and December.

[19] 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.

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

[21] These estimated payments only take into account the shadow price of the flexible ramping constraint and the procurement quantity. The ISO filed in July and implemented in September a more comprehensive settlement approach. At this time, DMM has not 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.

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	$0.33	4%	0.5%	$53.34
2012	Dec	$1.58	9%	1.6%	$61.84

Almost half of flexible ramping payments to generators (48 percent in 2012) occurred when the system was unable to procure enough flexible ramping capacity to meet the requirement. Figure 3.1 shows the monthly flexible ramping payments to generators, which is the total procured volume times the shadow price of the constraint. The green bar shows the payments made during intervals with procurement shortfalls and the blue bar shows the payments in all other periods.

Figure 3.1 Monthly flexible ramping constraint payments to generators

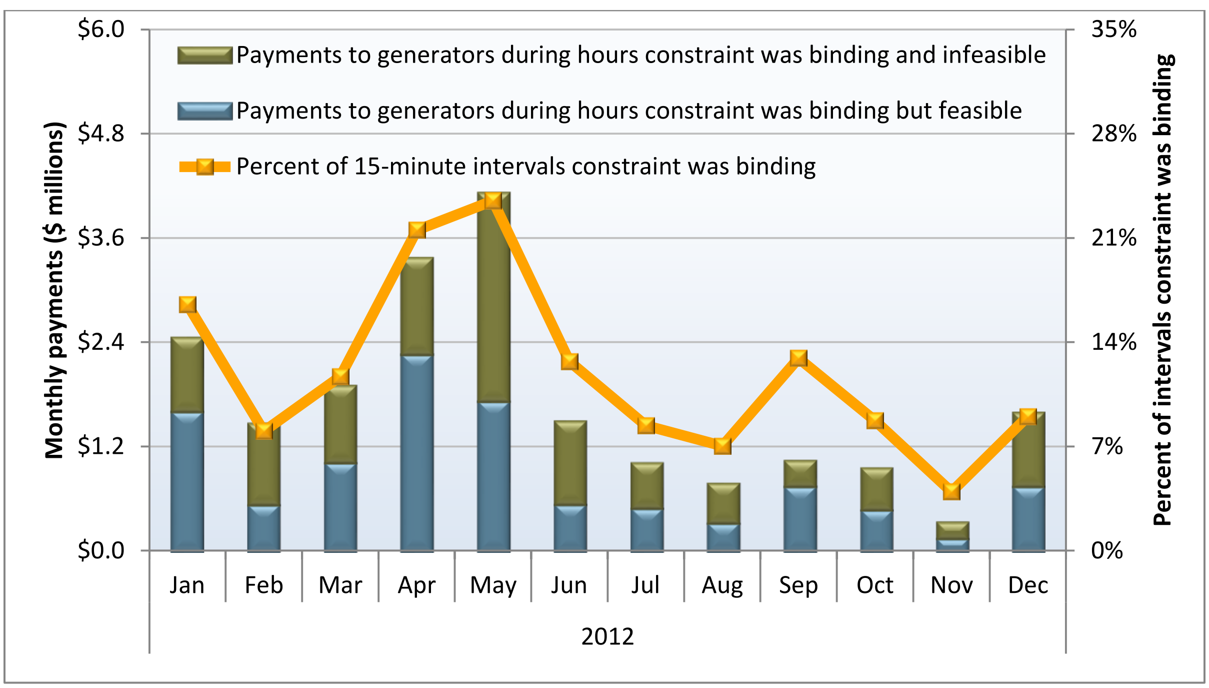
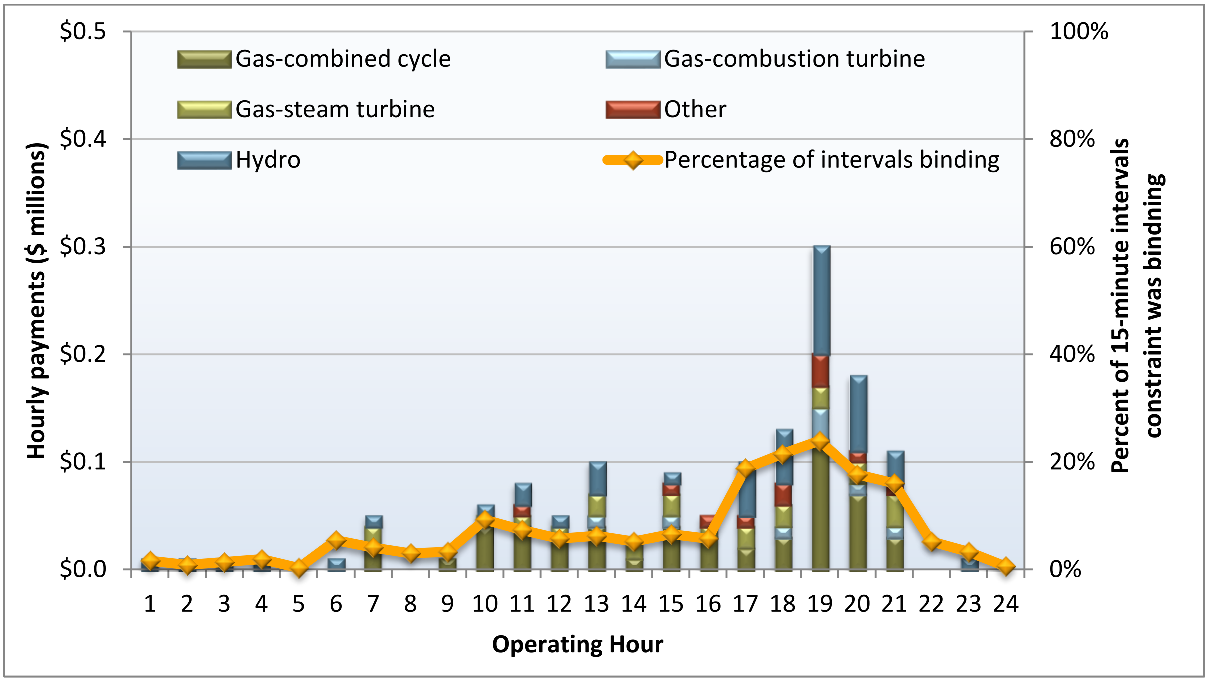


Figure 3.2 Hourly flexible ramping constraint payments to generators (October – December)



Most payments for ramping capacity occurred during the evening peak hours. In addition, most payments were for natural gas fired resources. Figure 3.2 shows the hourly flexible ramping payment distribution during the fourth quarter broken down by technology type. As shown in the graph, the highest payment periods were during hours ending 17 through 21. Also seen in the figure, natural gas-fired capacity accounted for about 60 percent of these payments with hydro-electric capacity accounting for 32 percent.

Real-time use of flexible ramping capacity

A useful metric for determining how effective the flexible ramping constraint is at 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 utilized 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 was comparable in the fourth quarter to the third quarter. Average hourly utilization ranged from 23 percent in the early morning to 36 percent in the late evening hours. Compared to the previous quarter, this shows a more balanced utilization across different hours of the day. Utilization increased in the early morning hours as lower load and unit maintenance outages decreased 5-minute ramping capacity in the early morning hours. Since the flexible ramping requirement was mostly flat during these periods, the utilization increased. Utilization declined in the evening hours due to ISO operator adjustments to the flexible ramping requirement. The ISO operators increased the flexible ramping requirements in the evening hours to prevent potential ramp-related contingencies and increase the ability of the system to balance during the steeper evening load periods. In many instances, the 5-minute real-time dispatch did not utilize all the capacity that was procured due to the increased requirements. Therefore, utilization decreased in the evening hours as more flexible ramping resources were procured to meet the higher requirements.

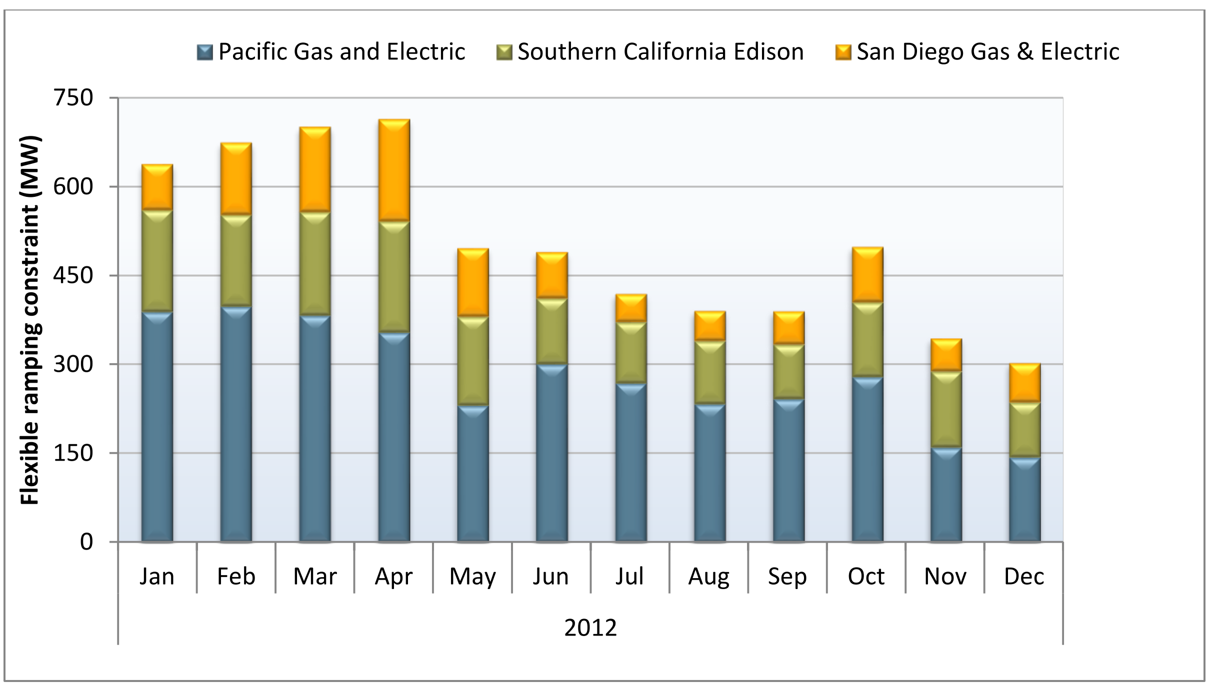
Flexible ramping regional procurement

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 3.3 shows the procurement of flexible ramping capacity by investor-owned utility area. During the year, around 56 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 more frequently in 2012 (see Section 1.3).

For example, in the second half of the year, around 62 MW of flexible ramping capacity was procured in the San Diego area, on average. Thus, only a small amount of dispatchable flexible ramping capacity was available to resolve ramping conditions in 5-minute real-time intervals with San Diego congestion. In the SCE and PG&E areas, average flexible ramping capacity procurement was around 109 MW and 221 MW, respectively. Considering the congestion that occurred in the SCE area in the third and fourth quarters, the procured flexible ramping capacity had a limited role in resolving 5-minute congestion related ramping issues in this region.

Figure 3.3 Flexible ramping constraint by investor-owned utility area



Recommendation

DMM continues to recommend that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in the 15-minute real-time pre-dispatch. DMM believes that evaluating commitment decisions is an important measure of the overall effectiveness of the constraint.[22] In addition, identifying commitment changes caused by the flexible ramping constraint will help in calculating secondary costs related to the flexible ramping constraint. These secondary costs include additional ancillary services payments and additional real-time bid cost recovery payments paid to short-term units committed to deliver energy and displace capacity on other units to provide flexible ramping capacity.

[22] The ISO is planning to add new model functionality that will indicate which units were added by the flexible ramping constraint.