California Independent System Operator Corporation

California ISO

Q3 2015 Report on Market Issues and Performance

November 16, 2015

Prepared by: Department of Market Monitoring

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Executive summary

This report covers market performance during the third quarter of 2015 (July – September). Market performance during this quarter was shaped by a variety of factors related to load forecasting.

- Challenges in load forecasting affected prices throughout the quarter. Days with significant day-ahead under-scheduling by participants and under-forecasting by the ISO tended to result in high real-time prices, including significant price spikes. When forecasts were higher than actual loads, real-time prices tended to be lower than day-ahead prices.
- On the days with the highest loads during the quarter (>40,000 MW), day-ahead load forecasts tended to overestimate the load during the peak hours of the day. However, during peak summer load hours when the load was underestimated in the day-ahead market, the difference tended to be off by a lot, contributing to high prices in real time.
- Load forecasts tended to be lower than actual loads on high temperature days. This was because of temperature forecast service models used in the load forecast calculation being affected by the strong El Niño effects. The load forecasts, which include behind-the-meter rooftop solar, were also affected by the record precipitation and regional monsoonal cloud cover in Southern California.
- Forecast uncertainty led operators to, at times, increase residual unit commitment target levels and make exceptional dispatches in order to ensure reliability.

Other highlights in the third quarter include the following:

- Day-ahead prices for the quarter were stable and significantly lower than last year, in both peak and off-peak periods. This was primarily driven by low natural gas prices.
- Real-time prices continued to be lower than day-ahead prices for the quarter. Although monthly average real-time energy prices for peak and off-peak periods tended to be lower than day-ahead prices, load forecast errors on several days with particularly high loads resulted in some very high real-time prices during the peak hours. Days when this occurred increased overall monthly average real-time prices significantly.
- There were very few price spikes in the 15-minute market during the quarter, and relatively few price spikes in the 5-minute market in July and August. During September there was a relatively high percentage of intervals when the prices spiked over $1,000/MWh in the 5-minute market, which occurred primarily on days when participants under-scheduled and the ISO under-forecast load in the day-ahead market. There were very few intervals with negative price spikes in both real-time markets during the quarter.
- Congestion for the quarter was relatively low overall, and had a relatively low impact on average load area prices. Planned transmission outages, which contributed to the congestion in the south-to-north direction on Path 15 in the second quarter, ended in June and resulted in significantly less congestion during this quarter.
- Revenue inadequacy from congestion revenue rights before accounting for auction revenues fell from $45 million in the second quarter of 2015 to $35 million in the third quarter. This shortfall is considerably smaller than the third quarter of 2014, which totaled $90 million. With auction

revenues, revenue inadequacy was $5 million in the third quarter, down from $8 million in the second quarter.

In 2014, the ISO took several measures to reduce revenue inadequacy. While accumulating at a slower pace than 2014, revenue inadequacy in the first nine months of 2015 remains elevated compared to previous years at $96 million. DMM recommends that the ISO continue to investigate measures to address revenue inadequacy issues, which includes the alternative allocation of revenue inadequacy costs to congestion revenue rights holders on a constraint specific basis.[1]

- Residual unit commitment levels increased by almost 90 percent in the third quarter of 2015 compared to the third quarter of 2014. This increase is primarily driven by an increase in net virtual supply along with higher loads and operator adjustments. While the majority of resources committed by the residual unit commitment were short-start resources that do not receive a day-ahead binding commitment, most resources that received bid cost recovery were long-start resources.
- Bid cost recovery payments were approximately $31 million in the third quarter of 2015, compared to $20 million in the third quarter of 2014 and $26 million in the second quarter of 2015. This increase occurred partly because of increased residual unit commitments that offset virtual supply. In addition, as noted above, temperature and load forecast uncertainty led operators to sometimes increase residual unit commitment target levels and make exceptional dispatches to ensure reliability. This also contributed to bid cost recovery payments.
- Cleared virtual supply exceeded cleared virtual demand by about 880 MW per hour on average, an increase from about 800 MW of net virtual supply in the previous quarter. Total convergence bidding revenue for the quarter, adjusted for bid cost recovery costs, was about $5 million, a decrease from about $8.4 million in the previous quarter.
- Almost all imports scheduled in the day-ahead market continue to be self-scheduled in real time rather than re-bid in the real-time market. This overall trend has continued since FERC Order No. 764 market changes were implemented in May 2014.
- The volume of 15-minute dispatchable import bids decreased by 14 percent compared to the second quarter, averaging 355 MW each hour in the third quarter. In addition, 15-minute dispatchable economic export bids increased to an average of 210 MW in the third quarter, compared to 190 MW in the second quarter.
- Most of the economic bidding of 15-minute dispatchable imports and exports continued to be submitted by a small number of scheduling coordinators on just three inter-ties (Malin, Palo Verde and Rancho Seco).
- Flexible ramping constraint payments were around $1.3 million in the third quarter, up from $0.7 million in the previous quarter. The flexible ramping constraint requirement remained highly volatile and was more often set to either the lower or upper bounds of the requirements compared to the second quarter. This was the result of implementing the automated requirement tool that currently uses a limited sample of data.

[1] *Allocating CRR Revenue Inadequacy by Constraint to CRR Holders*, Department of Market Monitoring, October 6, 2014: http://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

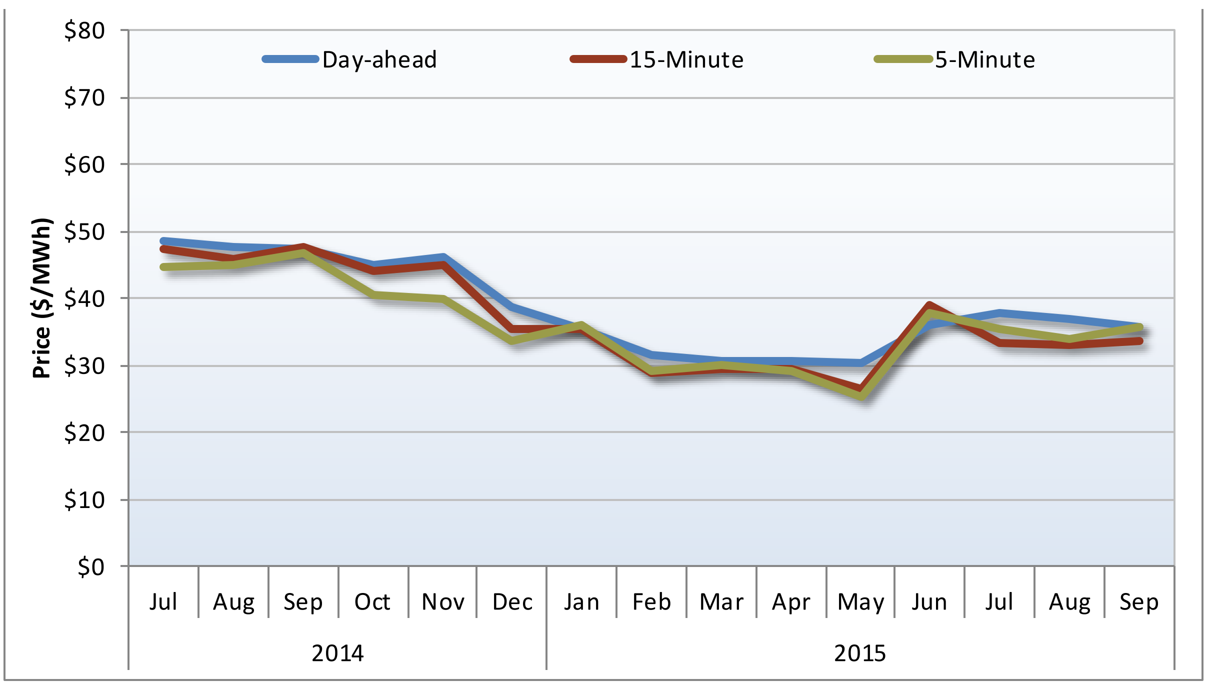
- During most intervals, prices in the energy imbalance market remained highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand. The frequency of energy relaxations remained low in the third quarter compared to the first months of EIM, whereas the frequency of flexible ramping constraints increased. Overall EIM performance is analyzed in detail in Section 3.

Energy market performance

This section provides a more detailed summary of energy market performance in the third quarter.

Average energy prices remained relatively level in the third quarter. Average day-ahead prices were higher than real-time prices in all peak and off-peak periods in the quarter except during off-peak hours in September, when extremely high real-time prices on September 20 drove average real-time prices higher. Average prices decreased in July from June but remained fairly constant afterwards (see Figure E.1). Prices in the third quarter were higher than in the second quarter as loads increased, and were lower than the third quarter of 2014 as natural gas prices were lower. Compared to the third quarter of 2014, hour-ahead prices tracked other real-time prices more closely.

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



Upward price spikes increased in September. Price spikes above $250/MWh in the 15-minute market occurred in less than 0.1 percent of intervals during the third quarter, a decrease from about 0.2 percent in the previous quarter. The frequency of price spikes over $250/MWh in the 5-minute market was 0.4 percent, a decline from 0.7 percent in the previous quarter. The majority of the upward volatility in both markets occurred in September. Almost half of the instances in September occurred on September 20, as a result of higher than anticipated loads as well as import limitations.

The frequency of negative prices fell in the third quarter. Negative prices occurred in less than 1 percent of the intervals in both the 15-minute and 5-minute markets in the third quarter at load area prices. This was down from 5 percent and 8 percent, respectively, in the second quarter. The decline in negative price spikes was consistent with the completion of a planned outage that lowered the rating of Path 15 in the second quarter and increases in seasonal load.

Congestion decreased as Path 15 outages ended. Much of the congestion in the second quarter was related to planned transmission outages associated with Path 15, which began in mid-March and continued until early June. Congestion declined significantly in the third quarter with the completion of this outage. Congestion on constraints increased overall average day-ahead prices in the Pacific Gas and Electric area by about 0.5 percent, and affected the San Diego Gas and Electric and Southern California Edison prices by about $0.01/MWh and $0.04/MWh, respectively.

Congestion revenue right revenue inadequacy remained elevated. Revenue inadequacy before accounting for auction revenues remained relatively high at $35 million in the third quarter of 2015, compared to $90 million from the third quarter of 2014. The balancing account deficit, which includes auction revenues, fell from $55 million in the third quarter of 2014 to $5 million in 2015. In 2014, with annual revenue inadequacy of nearly $200 million and a balancing account deficit of about $95 million, the ISO took several measures to reduce revenue inadequacy. While revenue inadequacy is accumulating at a slower pace than 2014, in the first nine months of 2015 it remained elevated compared to earlier years at about $96 million before accounting for auction revenues.

DMM recommends that the ISO continue to investigate measures to address revenue inadequacy issues including the alternative allocation of revenue inadequacy costs to congestion revenue rights holders on a constraint specific basis. This alternative allocation method would limit the amount of revenues that could be transferred from load-serving entities to congestion revenue rights holders through uplift. Moreover, this allocation method would reduce the incentive for entities purchasing congestion revenue rights to target modeling differences that create revenue inadequacy costs.[2]

Residual unit commitment increased because of virtual supply. Residual unit commitment levels increased by almost 90 percent in the third quarter of 2015 compared to the third quarter of 2014. This increase is primarily driven by an increase in net virtual supply along with higher loads. Out of the roughly 625 MW hourly average volume of residual unit commitment capacity in the third quarter, the capacity committed to operate at minimum load averaged just under 60 MW (9 percent) each hour. Moreover, 43 percent (24 MW) of this capacity was from long-start units that are committed to be on line by the residual unit commitment process. The total direct cost of residual unit commitment was about $0.09 million in the third quarter, or about 34 percent of the direct cost of $0.28 million in the previous quarter.

Residual unit commitment bid cost recovery drove costs higher. Bid cost recovery payments were approximately $31 million in the third quarter of 2015, compared to $20 million in the third quarter of 2014 and $26 million in the second quarter of 2015. Residual unit commitment bid cost recovery payments increased from $0.8 million in the second quarter to almost $10 million in the third quarter. About three-quarters of this bid cost recovery came from long-start units that were committed in the residual unit commitment process rather than by the real-time market.

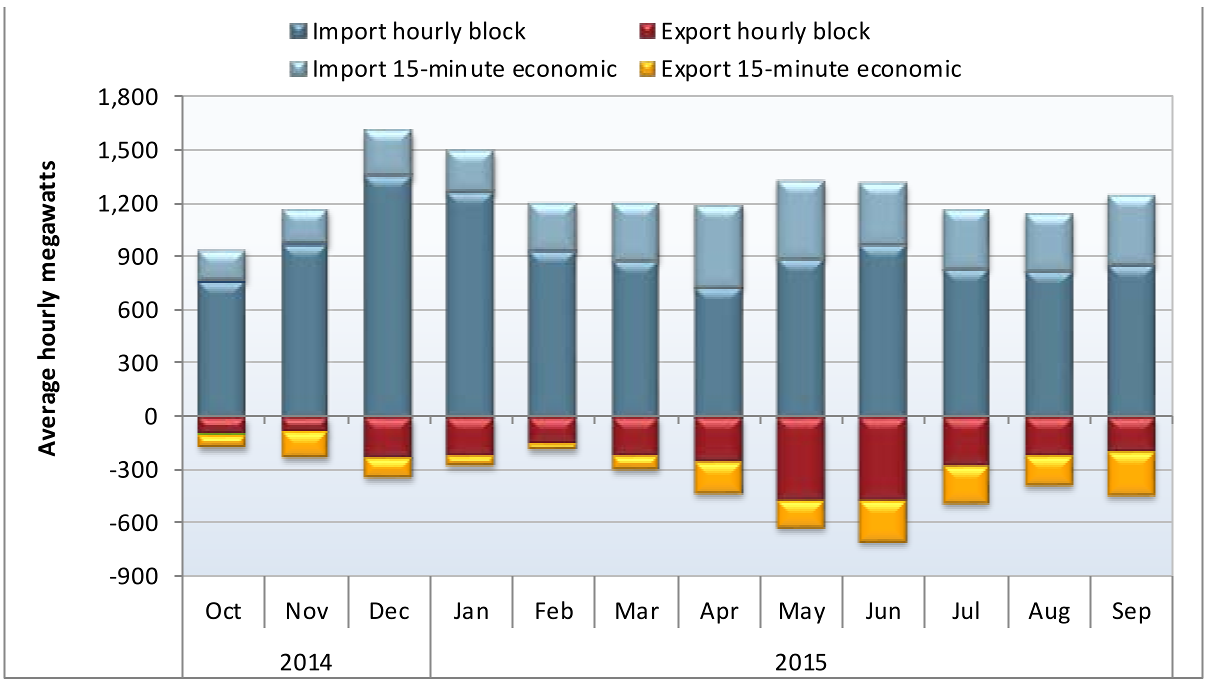
[2] *Allocating CRR Revenue Inadequacy by Constraint to CRR Holders*, Department of Market Monitoring, October 6, 2014: http://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

Convergence bidding revenues fell because of bid cost recovery allocation. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 880 MW on average, an increase from 800 MW of net virtual supply in the previous quarter. This is also the largest quarterly level of virtual supply since the third quarter of 2014. As a result of the large virtual supply positions, residual unit commitment bid cost recovery increased, decreasing convergence bidding net revenues. Bid cost recovery costs allocated to virtual supply were $4.7 million in the third quarter, up from about $1 million in the second quarter. Total convergence bidding revenue for the quarter, adjusted for bid cost recovery costs, was about $5 million, a decrease from about $8.4 million in the previous quarter.

Special issues

Economic bids of exports in the 15-minute market increased. When 15-minute scheduling on inter-ties was implemented in May 2014, there was a significant decrease in the amount of inter-tie bids into the real-time market as well as an increase in the volume of self-scheduled inter-tie transactions. This overall trend continued into the third quarter. In addition, real-time economic bidding of exports increased in the third quarter (see Figure E.2), whereas the real-time economic bidding of imports decreased. Most of the 15-minute dispatchable bids continued to be submitted by a small number of scheduling coordinators on just three inter-ties (Malin, Palo Verde and Rancho Seco).

Figure E.2 Economic import and export bids by bidding option



Of the economic inter-tie bids in the real-time markets, about 30 percent of import bids and 48 percent of export bids were available for dispatch on a 15-minute basis. The remaining bids were for fixed hourly blocks. The volume of 15-minute dispatchable import bids decreased by 14 percent compared to the second quarter, averaging 355 MW each hour in the third quarter. Economic 15-minute dispatchable export bids increased to an average of 210 MW in the third quarter, compared to 190 MW in the second quarter. The volume of 15-minute economic export bids in the third quarter was the highest quarterly value since 15-minute inter-tie bidding began in May 2014.

Flexible ramping constraint requirements remained highly volatile. The ISO automated the flexible ramping constraint requirement in late March upon implementing the balancing area ramp requirement tool. Because the calculation only uses a very limited set of historical observations, there was very high variability in the flexible ramping requirements from one interval to the next in both the ISO and EIM areas. In the third quarter, the variability decreased compared to the second quarter but remained significantly higher than prior to implementation of the automated tool. Further, the requirement was more often equal to either the lower or upper bounds of the requirements compared to the second quarter because of the limited sample of data used to calculate the requirement. The average flexible ramping constraint requirement increased in both the ISO and EIM areas.

1 Market performance

This section highlights key performance indicators of market performance in the third quarter.

- Day-ahead prices for the quarter were stable and lower than last year, in both peak and off-peak periods. This was primarily driven by lower natural gas prices.
- Real-time prices continued to be lower than day-ahead prices for the quarter. Although monthly average real-time energy prices for peak and off-peak periods tended to be lower than day-ahead prices, higher temperatures that led to higher than expected load on several days with particularly high loads resulted in some very high real-time prices during the quarter.
- There were very few price spikes in the 15-minute market during the quarter, and relatively few price spikes in the 5-minute market in July and August. There was a relatively high percentage of intervals when prices spiked over $1,000/MWh in the 5-minute market during September, primarily on days when load was under-scheduled and under-forecast in the day-ahead. There were very few intervals with negative price spikes in both the real-time markets in the third quarter.
- Overall congestion levels for the quarter were low and had a relatively small impact on average load area prices. Planned transmission outages that contributed to the congestion in the south-to-north direction on Path 15, where significant congestion was observed last quarter, ended in June and resulted in significantly less congestion on Path 15 during this quarter.
- Revenue inadequacy from congestion revenue rights fell to $35 million in the third quarter from $45 million in the second quarter. This shortfall is considerably smaller than the third quarter of 2014, which totaled $90 million. In 2014, the ISO took several measures to reduce revenue inadequacy. While accumulating at a slower pace than 2014, revenue inadequacy in the first nine months of 2015 remains elevated at $96 million. DMM recommends that the ISO continue to investigate measures to address revenue inadequacy issues, which includes the alternative allocation of revenue inadequacy costs to congestion revenue rights holders on a constraint specific basis.
- Bid cost recovery payments were just above $31 million in the second quarter, compared to $20 million in the second quarter of 2014 and $26 million in the second quarter of 2015. This increase is primarily attributable to increases in residual unit commitment bid cost recovery, which was $9.7 million in the third quarter compared to $0.8 million in the second quarter.
- Residual unit commitment levels increased by almost 90 percent in the third quarter of 2015 compared to the third quarter of 2014. This was primarily driven by an increase in net virtual supply along with higher loads and operator adjustments. While the majority of resources committed by the residual unit commitment were short-start resources that do not receive a binding day-ahead commitment, most resources that received bid cost recovery were long-start resources.
- Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 880 MW on average, an increase from 800 MW of net virtual supply in the previous quarter. Total convergence bidding revenue for the quarter, adjusted for bid cost recovery costs, was about $5 million, a decrease from about $8.4 million in the previous quarter.

1.1 Energy market performance

This section assesses the efficiency of the energy market based on an analysis of day-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources.

Figure 1.1 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively. As seen in these figures, average day-ahead price levels were higher than real-time prices in most peak and off-peak periods in the quarter. Overall, prices in the third quarter were more stable than previous quarters, while remaining lower than the third quarter of 2014.

- Average day-ahead prices were about the same in July, August, and September. In July, day-ahead prices were the highest during the quarter at $41/MWh during the peak period and $33/MWh for the off-peak period. Overall, day-ahead prices were higher than 15-minute and 5-minute market prices for the quarter.
- In the third quarter, average peak system prices in the 15-minute market were lower than day-ahead prices in all three months by a an average of $5/MWh. Off-peak 15-minute prices were lower than day-ahead prices in July and August by about $3/MWh. The 15-minute market average off-peak system prices moved higher than day-ahead prices in September by about $1/MWh.
- The 5-minute market prices were higher than 15-minute prices in peak hours during the quarter. Peak period average system prices in the 5-minute market were lower than day-ahead market prices during the entire quarter. In off-peak periods, 5-minute prices were lower than day-ahead prices and close to 15-minute prices during the entire quarter.
- On a monthly average basis, hour-ahead prices were lower than day-ahead prices in all three months. The average difference between day-ahead and hour-ahead prices was about $4/MWh for peak hours and about $2.50/MWh for off-peak hours. Compared to the third quarter of 2014, hour-ahead prices in the third quarter of 2015 tracked other real-time prices much more closely.

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

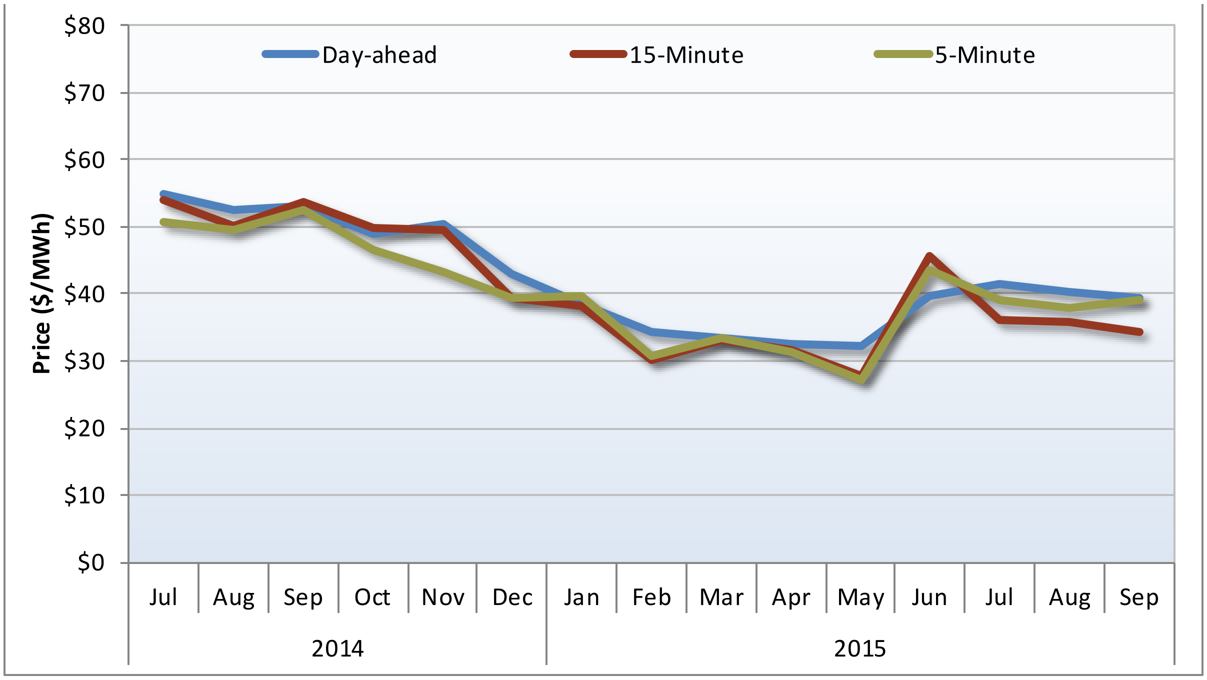


Figure 1.2 Average monthly off-peak prices – system marginal energy price

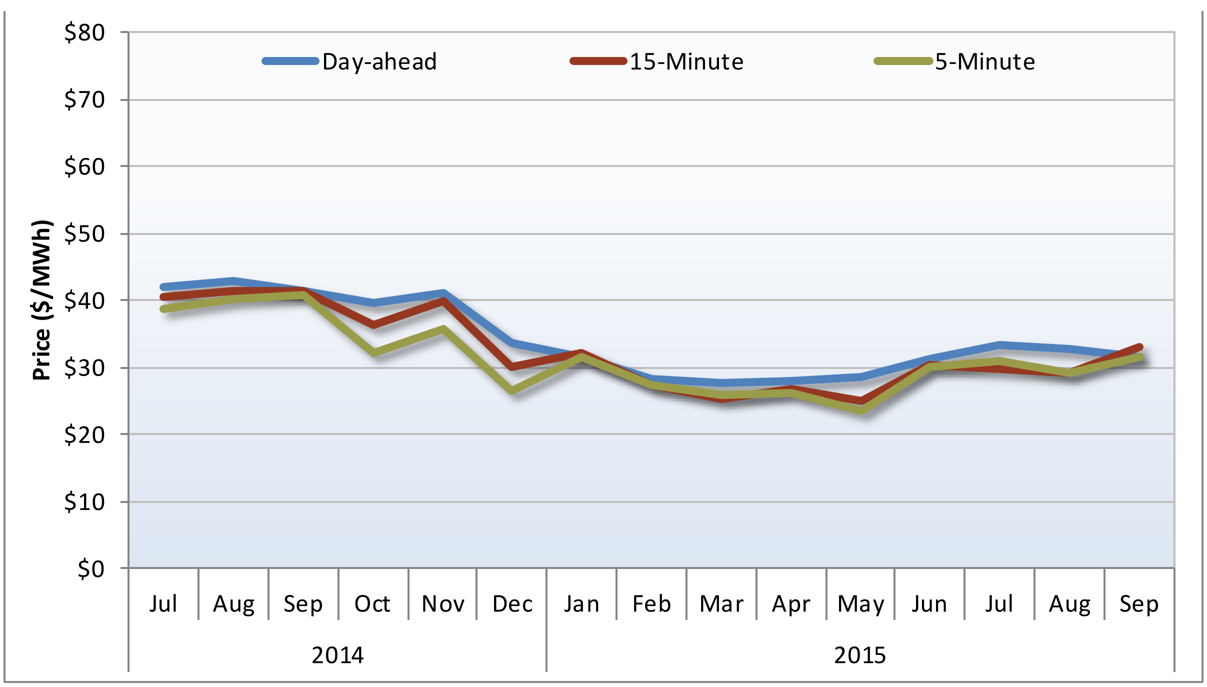


Figure 1.3 Hourly comparison of system marginal energy prices (July – September)

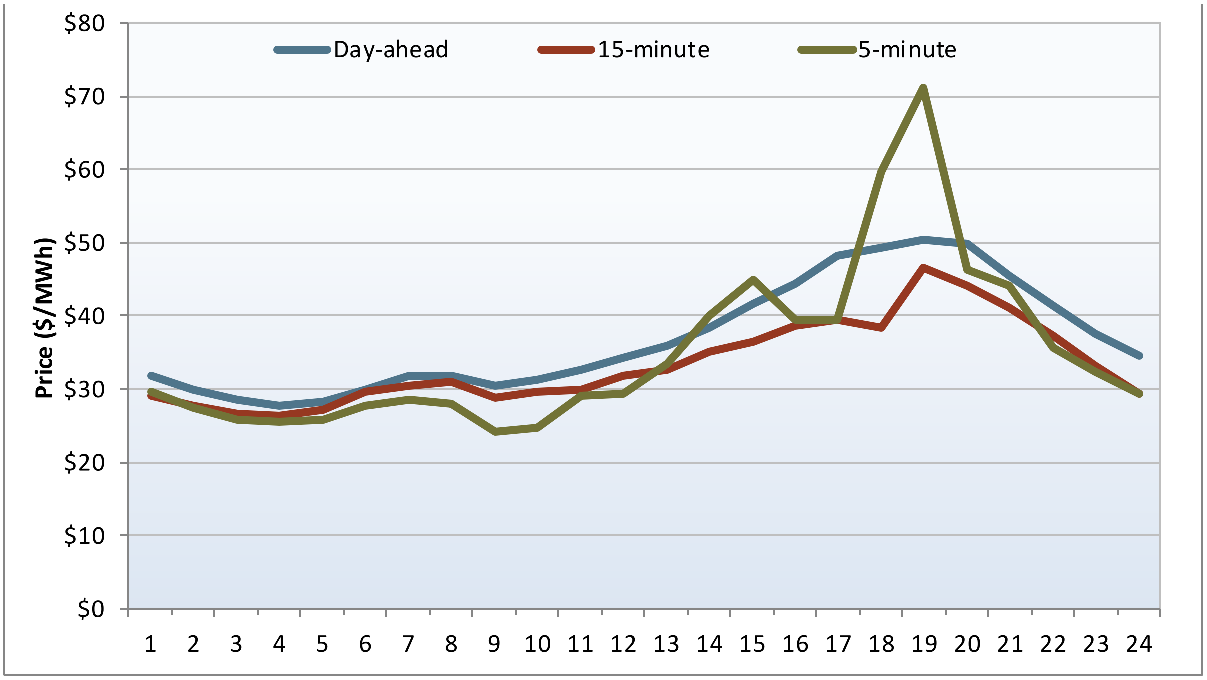


Figure 1.4 illustrates the system marginal energy prices on an hourly basis in the third quarter. Average prices in the three real-time markets were less than the day-ahead prices in the morning and late evening hours. Notably, prices in the 5-minute market were higher than the other three markets in hours ending 18 and 19. In hour ending 19, real-time prices averaged about $21/MWh higher than day-ahead prices. In contrast, 15-minute market prices were consistently lower than day-ahead prices over the day.

1.2 Real-time price variability

Real-time market prices can be highly volatile with periods of extreme positive and negative price spikes. Even a short period of volatility can have a significant impact on average prices. The frequency of both positive and negative price spikes decreased in both the 15-minute and 5-minute markets in the third quarter compared to previous periods.

Frequency of price spikes

Overall, positive price spikes were infrequent in both the 15-minute and 5-minute markets in the third quarter. Prices above $250/MWh were observed in less than 0.1 percent of intervals in the 15-minute market and about 0.4 percent of intervals in the 5-minute market.

Figure 1.4 and Figure 1.5 show the frequency of positive price spikes occurring in the 15-minute market and 5-minute market, respectively. In the third quarter, the frequency of price spikes in the 5-minute market was about 0.4 percent, compared to 0.7 percent in the second quarter of 2015. The figures show an increase in the frequency of positive price spikes in September. Of the 55 intervals with price spikes in September, 45 percent of these instances occurred on September 20 where there were high system-wide prices related to low load forecasts and import limitations. Additional price spikes were associated with regional congestion.

During July and August, as with previous quarters, negatively priced intervals were more frequent than high price intervals. In September, high price intervals were slightly more frequent than negatively priced intervals. In the 15-minute market, negative prices were observed in less than 1 percent of intervals during the quarter, a decrease from 5 percent in the previous quarter. Negative prices were similarly infrequent in the 5-minute market, occurring in less than 1 percent of intervals, compared to 8 percent in the second quarter.

Figure 1.6 and Figure 1.7 show the frequency of negative price spikes since July 2014 in the 15-minute and 5-minute markets for the past 15 months. August had the highest frequency of negative prices in both markets over the quarter. About 0.8 percent of intervals in the 15-minute market in August had negative prices, while 1.3 percent of intervals in the 5-minute market in August were negative. Negative prices in September occurred in 0.1 percent of intervals in the 15-minute market and 0.4 percent of intervals in the 5-minute market; this is the lowest frequency of negative prices since September last year. The decline in negative price spikes is consistent with the completion of the planned outage that lowered the rating of Path 15 in the second quarter and increases in seasonal load.

Figure 1.4 Frequency of positive 15-minute price spikes (all LAP areas)

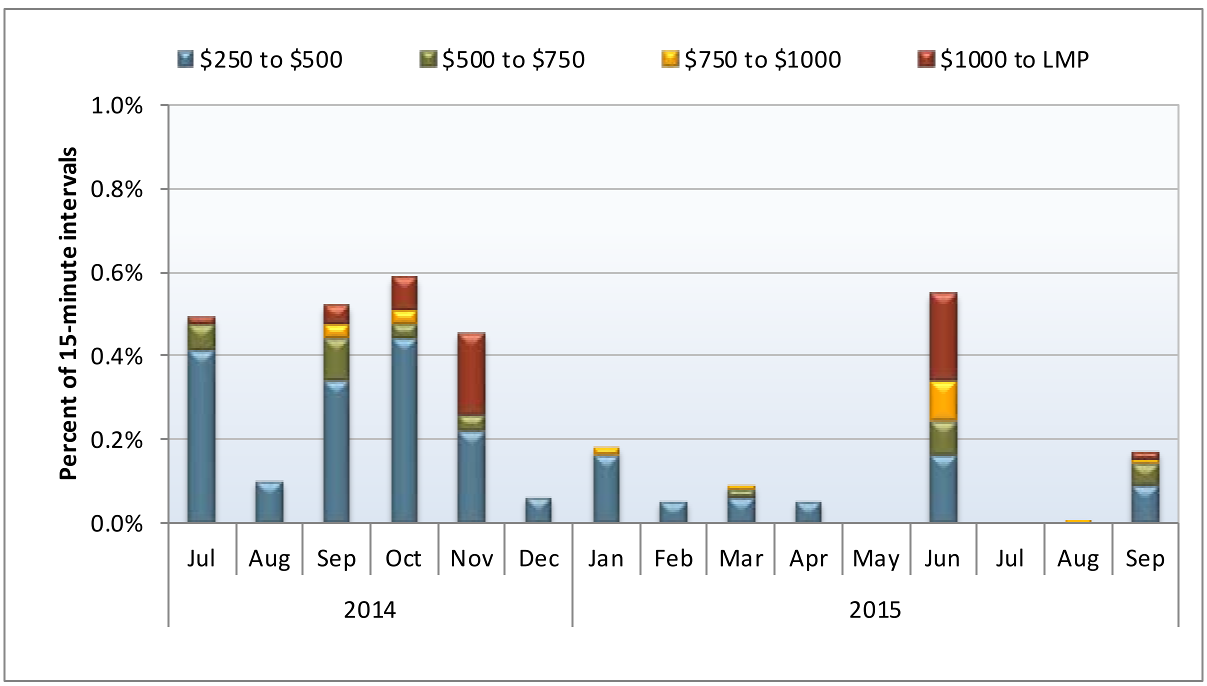


Figure 1.5 Frequency of positive 5-minute price spikes (all LAP areas)

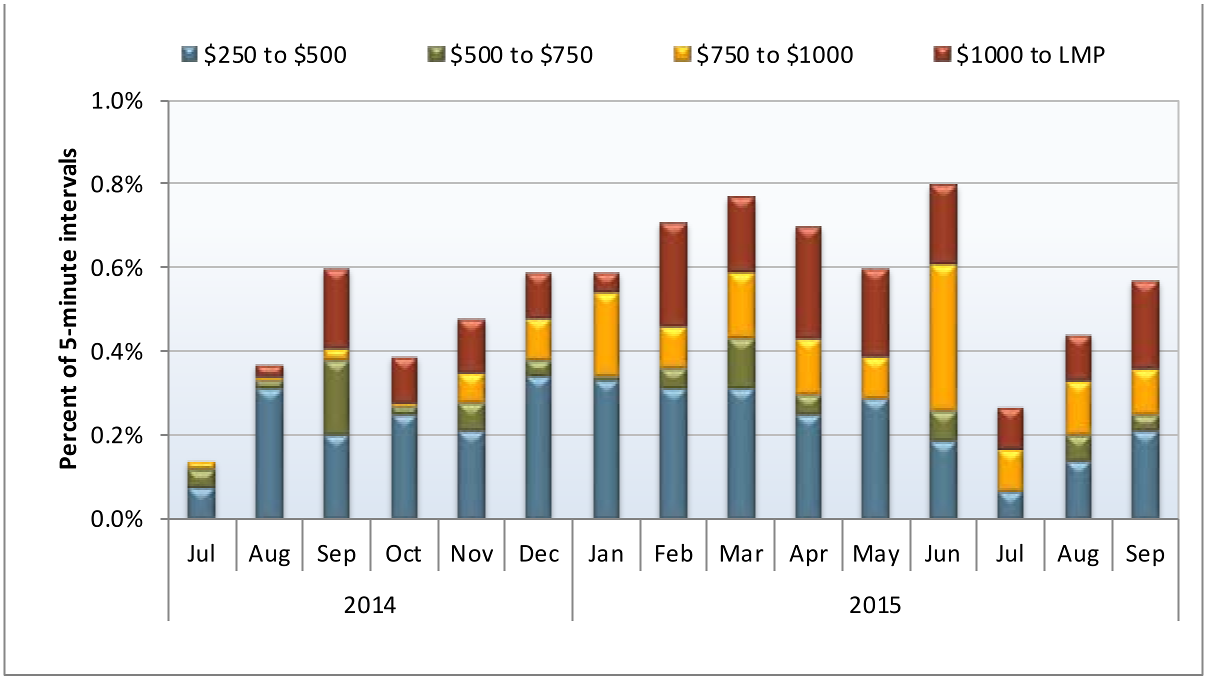


Figure 1.6 Frequency of negative 15-minute price spikes (all LAP areas)

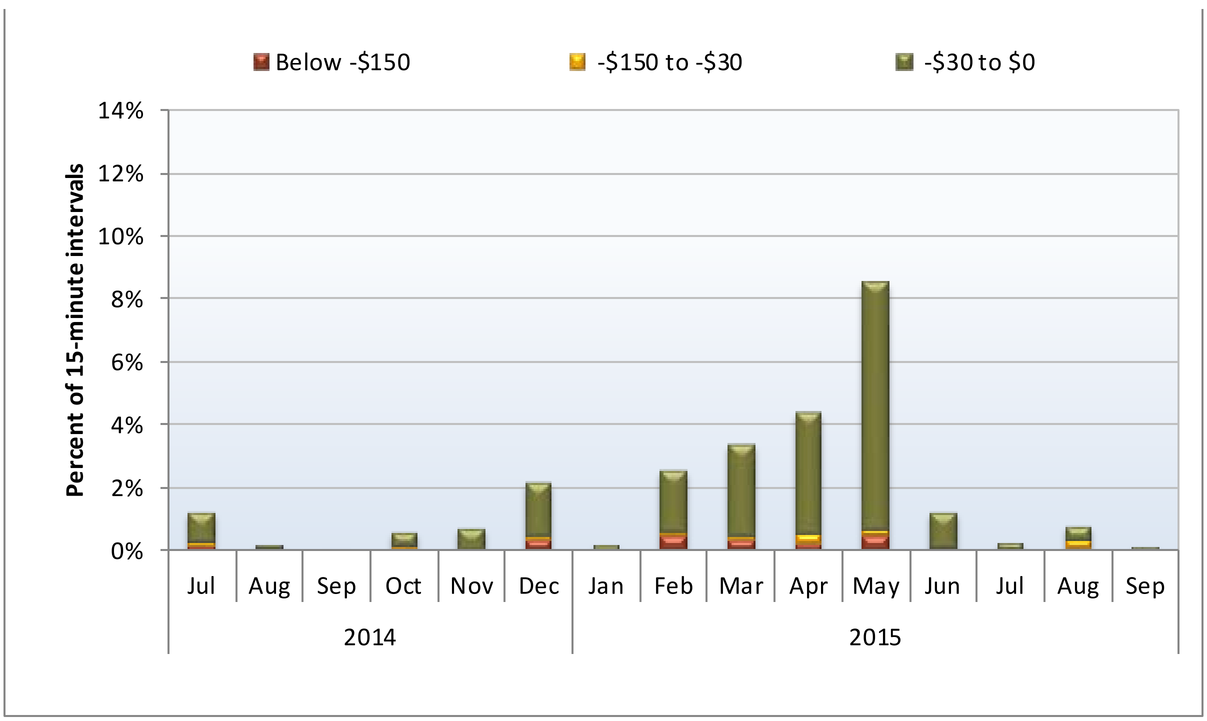
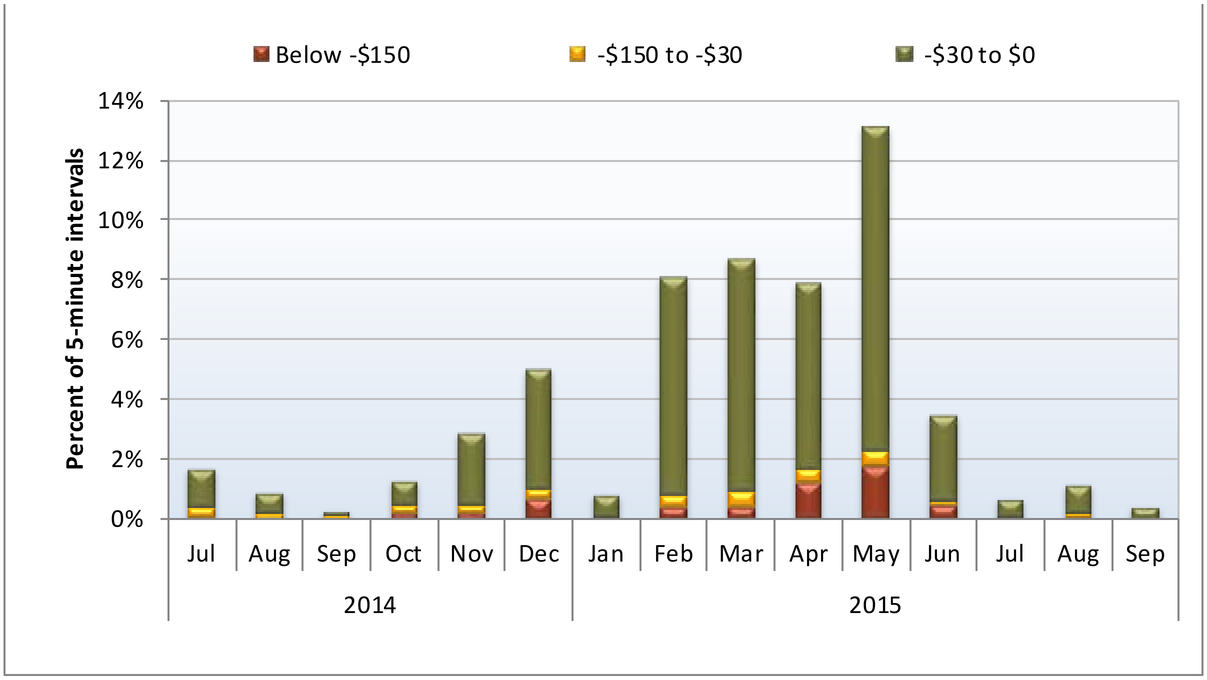


Figure 1.7 Frequency of negative 5-minute price spikes (all LAP areas)



1.3 Congestion

Congestion within the ISO system was lower compared to the previous quarter, and had a relatively low impact on average load area prices. Congestion on constraints increased overall average day-ahead and 15-minute prices in the PG&E area by about 0.5 percent and 0.4 percent, respectively. Compared to the previous quarter, congestion had a lesser price impact in the SDG&E and SCE areas, affecting prices by about $0.01/MWh and $0.04/MWh, respectively, in the day-ahead market.

Much of the congestion in the second quarter was related to planned transmission outages associated with Path 15, which began in mid-March and continued until early June. Congestion declined significantly in the third quarter with the completion of these outages.

1.3.1 Congestion impacts of individual constraints

Day-ahead congestion

Compared to the previous quarter, the frequency and impact of congestion in the day-ahead market decreased in the third quarter.

In the PG&E area, the RM_TM21_NG constraint was the most congested constraint in the day-ahead market (see Table 1.1). Binding in about 7 percent of the hours, this constraint increased the prices in the PG&E area by $0.54/MWh, while prices in the SDG&E area decreased by about $0.47/MWh. This nomogram is activated to mitigate for the loss of the Round Mountain-Table Mountain #1 500 kV or the Round Mountain-Table Mountain #2 500 kV lines.

The Barre – Villa Park 220 kV line was the most binding constraint in the SCE area. The constraint protects for thermal overload from the contingency loss of the Barre – Lewis 220 kV line. This constraint was congested in about 4 percent of hours due to contingencies. When this constraint was binding, PG&E and SDG&E area prices decreased by about $0.43/MWh and $2.68/MWh, respectively, while prices increased in the SCE area by $0.86/MWh.

In SDG&E, the 22831_SYCAMORE_138_22124_CHCARITA_138_BR_1_1 constraint was the top binding constraint, and was congested in 6 percent of the hours in the third quarter. It solely affected the SDG&E area prices increasing them by $1.30/MWh. The 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1_1 and 22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1_1 constraints were the next most binding constraints in the SDG&E area, binding in 2 percent of the hours. Both the constraints had a negative impact on the SDG&E area prices, bringing the prices down by about $2/MWh.

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

		Frequency			Q1			Q2			Q3		
Area	Constraint	Q1	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	RM_TM21_NG			7.0%							$0.54		-$0.47
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1			1.4%							$3.24		
	30055_GATES1 _500_30900_GATES _230_XF_11_P		2.7%	0.7%				$0.70	-$0.60	-$0.59	$0.73	-$0.60	-$0.59
	PATH15_S-N		9.1%	0.5%				$4.05	-$3.65	-$3.42	$0.63	-$0.52	-$0.49
	LOSBANOSNORTH_BG			0.2%							$6.49	-$5.71	-$5.27
	PATH15_BG	6.2%	27.6%		$4.02	-$3.29	-$3.06	$4.54	-$3.86	-$3.64			
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		2.3%					$1.97	-$1.72	-$1.63			
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_1		1.5%					$2.02					
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_2		1.3%					$4.13	-$6.42	-$6.20			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		0.6%					$2.96	-$1.36				
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3		0.3%					$4.13	-$3.82	-$3.62			
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	9.0%	0.8%	3.9%	-$0.95	$0.92	$1.51	-$1.78	$2.51	-$0.41	-$0.43	$0.86	-$2.68
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.9%	0.9%	1.5%	-$0.74	$1.00	-$0.59				-$0.44	$0.57	
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.2%					-$0.41	$0.49	$0.40			
SDG&E	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1		0.6%	6.1%						$5.26			$1.30
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1		2.4%	2.4%						-$2.11			-$2.24
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			2.3%									-$1.83
	22609_OTAYMESA_230_22467_MLSXTAP _230_BR_1 _1			2.1%									$0.50
	22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1			1.3%									$1.14
	22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1	0.5%		1.3%			$6.85						$2.26
	22668_POWAY _69.0_22664_POMERADO_69.0_BR_1 _1			1.0%									$1.06
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		2.8%	0.6%						-$2.14			-$2.36
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1		1.3%	0.3%						$9.18			$5.55
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.3%	0.05%				-$5.06	$3.49	$7.21	-$13.67	$8.54	$12.63
	22716_SANLUSRY_230_22504_MISSION _230_BR_2 _1		0.2%						$0.70	-$5.89			
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	4.2%	1.3%				-$0.47	-$0.72		$1.17			
	SLIC 2584248 50002_OOS_TDM		0.6%							$4.70			
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	24.7%					$5.04						
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	13.1%			-$2.80	$1.70	$5.15						
	IVALLY-ELCNTO_230_BR_1_1	1.7%			-$0.05		$1.47						
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	1.5%			-$3.81	$2.35	$6.50						

15-minute market congestion

Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but often had a larger price effect. Table 1.2 shows the frequency and magnitude of 15-minute market congestion in the quarter.

Located in the SCE area, 24016_BARRE_230_24154_VILLA PK_230_BR_1_1, which protects for the loss of the Barre – Lewis 220 kV line, was the top binding constraint for the quarter. This constraint was binding in 0.8 percent of intervals and drove the SCE prices by $3.21/MWh and decreased the PG&E and SDG&E prices by about $1.45/MWh and $6.56/MWh, respectively.

PATH15_S-N and PATH26_N-S were the next most frequently binding constraints in the third quarter, congested in about 0.5 percent of all the intervals. PATH15_S-N increased the PG&E prices by $13.80/MWh and decreased SCE and SDG&E prices by about $13.31/MWh and $12.53/MWh, respectively. Conversely, PATH26_N-S constraint had a positive impact on both the SCE and SDG&E areas, driving prices up by $7.08/MWh and $6.68/MWh, respectively, while decreasing PG&E area prices by $9.46/MWh.

Table 1.2 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

		Frequency			Q1			Q2			Q3		
Area	Constraint	Q1	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	PATH15_S-N	1.0%	6.7%	0.5%	$16.27	-$16.36	-$15.30	$14.16	-$14.62	-$13.81	$13.80	-$13.31	-$12.53
	30055_GATES1 _500_30900_GATES _230_XF_11_P			0.4%							$6.72	-$5.41	-$5.26
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		0.3%					$6.59	-$6.62	-$6.29			
	6110_SOL10_NG		0.2%					$4.96	$2.13	$1.50			
	PATH15_BG	0.2%			$5.87	-$6.08	-$5.72						
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.5%	0.1%	0.8%	-$3.09	$7.15	$3.45	-$5.92	$16.52	$2.76	-$1.45	$3.21	-$6.56
	PATH26_N-S	0.1%		0.5%	-$46.75	$44.20	$41.92				-$9.46	$7.08	$6.68
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1			0.1%							-$5.14	$12.24	-$32.72
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1		0.5%							$14.09			
	SLIC 2584248 50002_SCIT		0.1%					-$4.18	$9.51	$9.92			
SDG&E	7820_TL 230S_OVERLOAD_NG			0.4%							-$1.97		$27.45
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			0.4%									-$6.42
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			0.2%									-$10.81
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1		0.1%						$9.67	-$100.16			
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.1%					-$5.35	$5.99	$10.80			
	SDGEIMP_BG		0.1%					-$1.74	-$1.74	$24.03			
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		0.1%						$3.57	-$30.20			
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	2.7%					$14.80						
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	1.7%			-$7.01	$8.42	$19.96						
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.5%			-$9.33	$10.25	$25.01						

Overall, congestion occurred more frequently in the day-ahead market than in the 15-minute market, but had a smaller price impact when binding. In the quarter, the price impact on the most significant binding elements was larger in the 15-minute market than the day-ahead market. For instance, the 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 constraint was binding in roughly 4 percent of hours in the day-ahead market compared to around 0.8 percent of intervals in the 15-minute market. While this constraint increased day-ahead prices in the SCE area by about $0.86/MWh, it increased prices by about $3.21/MWh in the 15-minute market.

Differences in congestion in the day-ahead and real-time markets occur as system conditions change, virtual bids liquidate, and constraints are adjusted to account for discrepancies between market and actual flows and to provide a reliability margin.

1.3.2 Impact of congestion on average prices

This section provides an assessment of differences between overall average regional prices in the day-ahead and 15-minute markets caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is 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 when taking into account both the frequency with which congestion occurs and the magnitude of the impact.[3] The congestion price impact differs across load areas and markets.

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

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.[4] This calculation can be done for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load area in the quarter by constraint.[5]

For the quarter, congestion in the day-ahead market increased all load area prices. Congestion in the day-ahead market increased PG&E prices by about 0.5 percent ($0.19/MWh), SCE area prices by about 0.1 percent ($0.04/MWh) and SDG&E area prices by about 0.04 percent ($0.01/MWh). Compared to the previous quarter, overall impact of the day-ahead market congestion on PG&E, SCE and SDG&E load area prices is smaller in the third quarter.

The 22831_SYCAMORE_138_22124_CHCARITA_138_BR_1_1 constraint had the largest overall impact on prices in the third quarter. This constraint increased prices in the SDG&E area by $0.08/MWh (0.22 percent) but had negligible impact on the other areas.

In the PG&E area, the 30915_MORROBAY_230_30916_SOLARSS_230_BR_1_1 constraint increased prices by $0.04/MWh (0.12 percent) with no impact on prices in the SDG&E and SCE areas.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.03%	$0.03	0.09%	-$0.06	-0.17%
22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1					$0.08	0.22%
RM_TM21_NG	$0.04	0.10%			-$0.03	-0.08%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.05	-0.15%
30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	$0.04	0.12%				
22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1					-$0.04	-0.11%
LOSBANOSNORTH_BG	$0.02	0.04%	-$0.01	-0.04%	-$0.01	-0.03%
22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1					$0.03	0.08%
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.01	-0.02%	$0.00	0.01%	$0.01	0.02%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.02%	$0.01	0.02%		
22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1					$0.02	0.04%
22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1					$0.02	0.04%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1					-$0.01	-0.04%
22609_OTAYMESA_230_22467_MLSXTAP _230_BR_1 _1					$0.01	0.03%
22668_POWAY _69.0_22664_POMERADO_69.0_BR_1 _1					$0.01	0.03%
PATH15_S-N	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
Other	$0.11	0.29%	$0.02	0.04%	$0.07	0.18%
Total	$0.19	0.5%	$0.04	0.1%	$0.01	0.04%

[4] On September 17, a software fix was made to address price separation at load area prices caused by inappropriately including shift factors of less than 2 percent. The ISO typically excludes shift factors below a 2 percent threshold.

[5] Due to data issues, details on specific constraints could not be calculated and were included in the ‘other’ category.

15-minute price impacts

Table 1.4 shows the overall impact of 15-minute congestion on average prices in each load area in the quarter by constraint.[6] Congestion in the 15-minute market was low overall. On a load area basis, congestion elevated the PG&E and SDG&E area prices by about $0.15/MWh (0.43 percent) and $0.01/MWh (0.02 percent), respectively, and had a small negative effect on SCE load area prices. Congestion was largest on Path 15 in the south-to-north direction, followed by congestion on Path 26 in the north-to-south direction.

Table 1.4 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
PATH15_S-N	$0.07	0.20%	-$0.07	-0.20%	-$0.06	-0.19%
PATH26_N-S	-$0.05	-0.13%	$0.03	0.10%	$0.03	0.10%
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.02%			$0.10	0.31%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	-0.01%	$0.03	0.08%	-$0.04	-0.13%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.03	0.08%	-$0.02	-0.06%	-$0.02	-0.06%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.02%	$0.01	0.04%	-$0.02	-0.04%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.03	-0.07%
22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1					-$0.02	-0.07%
Other	$0.11	0.33%	$0.00	0.01%	$0.06	0.18%
Total	$0.15	0.43%	-$0.01	-0.03%	$0.01	0.02%

1.4 Congestion revenue rights revenue adequacy

Congestion revenue rights are forward contracts on transmission capacity that settle on day-ahead congestion prices.[7] Congestion revenue right payments exceeded day-ahead market congestion rent collections in the third quarter. This created $34.8 million in revenue inadequacy before accounting for auction revenues.[8] With auction revenues accounted for, the deficit fell to $5.3 million during the third quarter.

Background

The market for congestion revenue rights is designed so that congestion rent collected from the day-ahead market should be sufficient to cover payments to congestion revenue rights holders. This is referred to as revenue adequacy.[9] Day-ahead congestion rents and congestion revenue right entitlement payments are placed in a balancing account. All revenues from the annual and monthly auction processes are also added to the balancing account which offsets deficits due to revenue

[6] Due to data issues, details on specific constraints could not be calculated and were included in the 'other' category.

[7] The *2014 Annual Report on Market Issues and Performance* offers general background information on congestion revenue rights. For more information, see: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

[8] Congested constraints can cause the amount paid for consuming power to exceed the amount paid for providing the power. This difference in payments is congestion rent.

[9] For a more detailed explanation of congestion revenue rights revenue adequacy and the simultaneous feasibility test, please see the ISO's 2014 reports on congestion revenue rights at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=6E3E0602-9DF9-4F7F-8557-3D7C99DCCBE8.

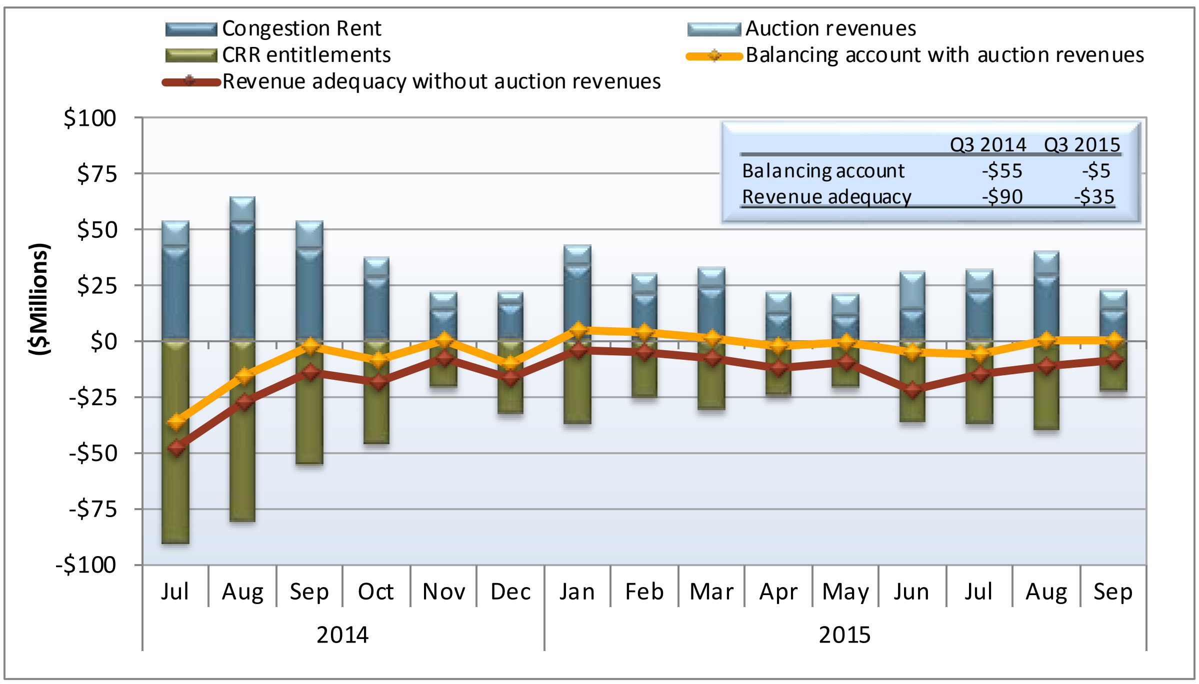
inadequacy, if needed. Monthly balancing account shortfalls or surpluses are allocated to measured demand.

Revenue inadequacy, when congestion rents are insufficient to cover payments to congestion revenue rights, can occur for a variety of reasons. Differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model is one of the major causes of revenue inadequacy. When there is less capacity available across a transmission constraint in the day-ahead market than the congestion revenue rights auction, the amount of congestion rent the day-ahead market can collect can be below the amount of congestion revenue right entitlements.

Revenue adequacy

Figure 1.8 shows the monthly revenues, payments, revenue adequacy, and balancing account values from July 2014 through September 2015.

Figure 1.8 Monthly revenue adequacy



- The dark blue bars represent day-ahead market congestion rent.
- The light blue bars show net revenues from the annual and monthly auctions for congestion revenue rights corresponding to each quarter. This includes revenues paid for positively priced congestion revenue rights in the direction of expected prevailing congestion, less payment made to entities purchasing negatively priced counter-flow congestion revenue rights.[10]
- The dark green bars show net payments made to holders of congestion revenue rights. This includes payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities holding counter-flow congestion revenue rights.

[10] Auction revenues from the seasonal auctions are divided into the months within the seasonal term based on the number of hours in each month for the congestion revenue right type (peak or off-peak).

- The orange line shows the monthly balancing account value which includes auction revenues.
- The red line shows the monthly revenue adequacy which excludes auction revenues.

As seen in Figure 1.12, revenue inadequacy before accounting for auction revenues in the third quarter was $35 million, down 61 percent from a shortfall of $90 million in the third quarter of 2014. The balancing account deficit improved by 90 percent to $5 million. Compared to 2014, revenue inadequacy in 2015 improved in absolute dollar terms but revenue inadequacy increased as a percent of congestion rent.

Third quarter revenue inadequacy in 2015 occurred with significantly less day-ahead market congestion rent ($65 million) in 2015 compared to the third quarter of 2014 ($135 million). As a percent of day-ahead congestion rents, third quarter congestion revenue right entitlements decreased to about 154 percent in 2015 from 166 percent in 2014.

Components of congestion revenue rights balancing account by market participant type

Table 1.5 compares the distribution of individual components of congestion revenue rights balancing account among different groups of congestion revenue rights holders and shows the final balance of revenue adequacy account for each participant type.[11] The columns include the following:

- **Net day-ahead congestion rents:** The congestion rent collections in the day-ahead market from market participants net of congestion rents passed through to existing transmission contracts and transmission ownership rights.
- **CRR settlement rule:** Charges from the congestion revenue rights settlement rule mechanism.[12]
- **CRR auction revenues:** The net revenues from the annual and monthly congestion revenue rights auctions.
- **CRR entitlements:** Net payments made to holders of congestion revenue rights, which include payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities purchasing counter-flow congestion revenue rights.
- **Final CRR account balance**: The sum of the first three columns, which represent collections made by the ISO, minus CRR entitlements which are paid out by the ISO.

For purposes of this analysis, congestion revenue rights holders are categorized as follows:

- Balancing authority areas outside the ISO system.
- Financial entities that own no physical power in the ISO system and participate in only the convergence bidding and congestion revenue rights markets.
- Marketers that participate by scheduling imports or exports on inter-ties and whose portfolios are not primarily focused on physical or financial participation in the ISO markets.

[11] ISO's final account balance in the table shows the difference between payments to the ISO and payments by the ISO. A negative balance means that the ISO paid more to the market participants than it received from them.

[12] If a market participant's convergence bidding positions impact the power flow and congestion on a constraint by a certain percentage and increase the value of the congestion revenue rights for the market participant, the ISO adjusts the payment by reducing the value of the congestion revenue rights.

- Physical generators who primarily participate in the ISO as physical generators.
- Physical load or entities who primarily participate in the ISO as load-serving entities.

As shown in Table 1.5, load-serving entities received the largest share of net revenues, collecting net revenues of $13 million in the third quarter of 2015. Most of these revenues resulted from allocations of congestion revenue rights made based on the volume of load served and auction revenues from counter-flow positions.[13] Load-serving entities on net used counter-flow positions to sell allocated rights back to the congestion revenue right auction.

Financial entities collected net revenues of nearly $6 million, which bid heavily in the monthly auctions, by speculating on and responding to congestion trends. Subtracting the day-ahead congestion from the revenues of financial participants can be misleading when trying to determine the profitability of the congestion revenue right positions. This is because the congestion revenue rights positions of financial participants are separate from their day-ahead congestion costs, which are primarily related to their convergence bidding positions.[14] Overall, financial entities earned over $16 million by purchasing transmission rights in the congestion revenue right auction for about $17 million and selling them for $33 million. Marketers and physical generation on net contributed nearly $3 million and $10 million, respectively, in payments into the balancing account.

Table 1.5 Components of CRR balancing account by market participant type (July – September)

Trading entities	Payments to the CRR Balancing Account ($ millions)				
	Net day-ahead congestion rents	CRR settlement rule	CRR auction revenues	CRR entitlements	Final CRR account balance
Balancing authority	$2.3			-$1.0	**$1.4**
Financial	$10.3	$0.0	$16.7	-$32.7	**-$5.7**
Marketer	$3.0	$0.0	$15.2	-$15.4	**$2.8**
Physical generation	$18.0	$0.0	$6.0	-$14.4	**$9.7**
Physical load	$30.9	$0.0	-$8.4	-$35.9	**-$13.4**
Total	**$64.5**	**$0.1**	**$29.6**	**-$99.4**	**-$5.3**

1.5 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet actual load in real time. The residual unit commitment market is run after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of physical supply cleared in the day-ahead market and the day-ahead forecast load. In addition, when the market clears with net virtual supply, residual unit commitment capacity is needed to replace the net virtual supply

[13] Negative auction revenues in Table 1.5 represent payments for the cleared counter-flow positions.

[14] Convergence bid positions could be net virtual supply or demand in the day-ahead market that are reversed in the real-time to arbitrage overall prices. Convergence bids can also be used to purchase transmission rights in the day-ahead market to sell to the real-time market similar to the purchase of transmission rights in the congestion revenue rights auction to sell to the day-ahead market.

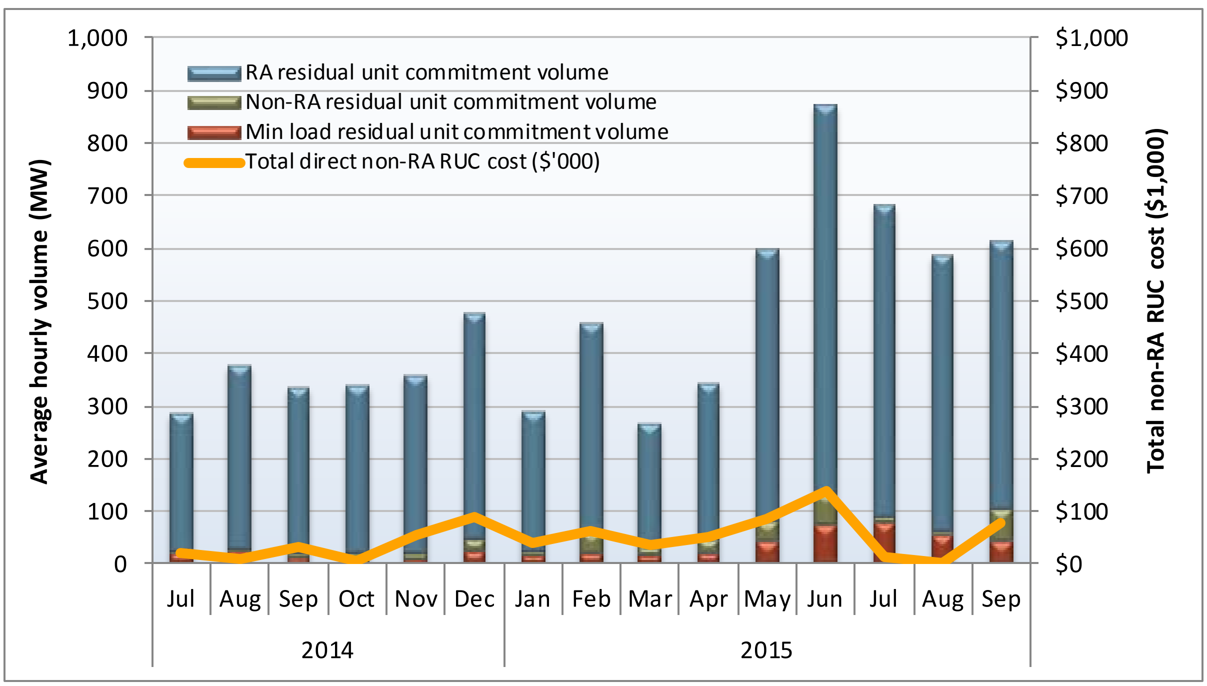
with physical supply. Capacity procured in the residual unit commitment must be bid into the real-time market.

While capacity procured in the residual unit commitment must be bid into the real-time market, only a fraction of this capacity is committed to be on line by the residual unit commitment process. Most of the capacity procured in the residual unit commitment process is from units that are already scheduled to be on line through the day-ahead market or from short-start units that do not need to be started up unless actually needed in real time.

1.5.1 Residual unit commitment costs and volumes

While total residual unit commitment volume increased slightly in the third quarter when compared to the previous quarter, it was up compared to 2014. Figure 1.9 shows monthly average hourly residual unit commitment procurement, categorized as either non-resource adequacy or resource adequacy and minimum load. Total residual unit commitment procurement rose from an average of 603 MW per hour in the second quarter to 627 MW per hour in the third quarter. Compared to the third quarter of 2014, there was an 89 percent increase in total residual unit commitment procurement in the third quarter of 2015.

Figure 1.9 Residual unit commitment costs and volume



Out of the 627 MW total average hourly volume of residual unit commitment capacity in the third quarter, the capacity committed to operate at minimum load averaged just 57 MW (9 percent) each hour. Moreover, 43 percent (24 MW) of this capacity was from long-start units which are committed to be on line by the residual unit commitment process.[15]

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in the residual unit commitment receive capacity payments.[16] As shown by the very small green segment of each bar in Figure 1.9, the non-resource adequacy residual unit commitment was low in the third quarter, averaging only 27 MW per hour. This was a decrease from 41 MW per hour in the previous quarter. The total direct cost of residual unit commitment, represented by the gold line in Figure 1.9, was about $0.09 million in the third quarter, about 34 percent of the direct cost of $0.28 million in the previous quarter.

1.5.2 Determinants of residual unit commitment procurement

As illustrated in Figure 1.10, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was over 80 percent higher in the third quarter of 2015 than in the third quarter of 2014.

The ISO in 2014 introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources.[17] This eligible intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.10.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor decreased residual unit commitment in all months of the third quarter similar to the third quarter of 2014. In addition, ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. This tool, noted as operator adjustments (red bar) in the figure, was used less frequently in the third quarter than in the second quarter and averaged less than 30 MW per hour.

Figure 1.11 illustrates the average hourly determinants of residual unit commitment procurement. Operator adjustments were concentrated in the peak load hours of the day, peaking in hours ending 14 through 21. While adjustments were low in the off-peak hours, net virtual supply was a major driver of residual unit commitment procurement in these periods. On average, day-ahead cleared capacity was always greater than day-ahead load forecast during all the hours in the third quarter. Intermittent resource adjustments were greatest during early morning and late evening hours.

[15] Long-start commitments are resources that require 300 or more minutes (5 hours) to start up. These resources receive binding commitment instructions from the residual unit commitment process. Short-start units receive an advisory commitment instruction in the residual unit commitment process, whereas the actual unit commitment decision for these units occurs in real time.

[16] Resource adequacy units receive bid cost recovery payments as well as payments through the resource adequacy process.

[17] Specifically, the adjustment is only made for PIRP resources that have positive schedules in the day-ahead market. PIRP resources that are not scheduled in the day-ahead market are not adjusted at this time.

Figure 1.10 Determinants of residual unit commitment procurement

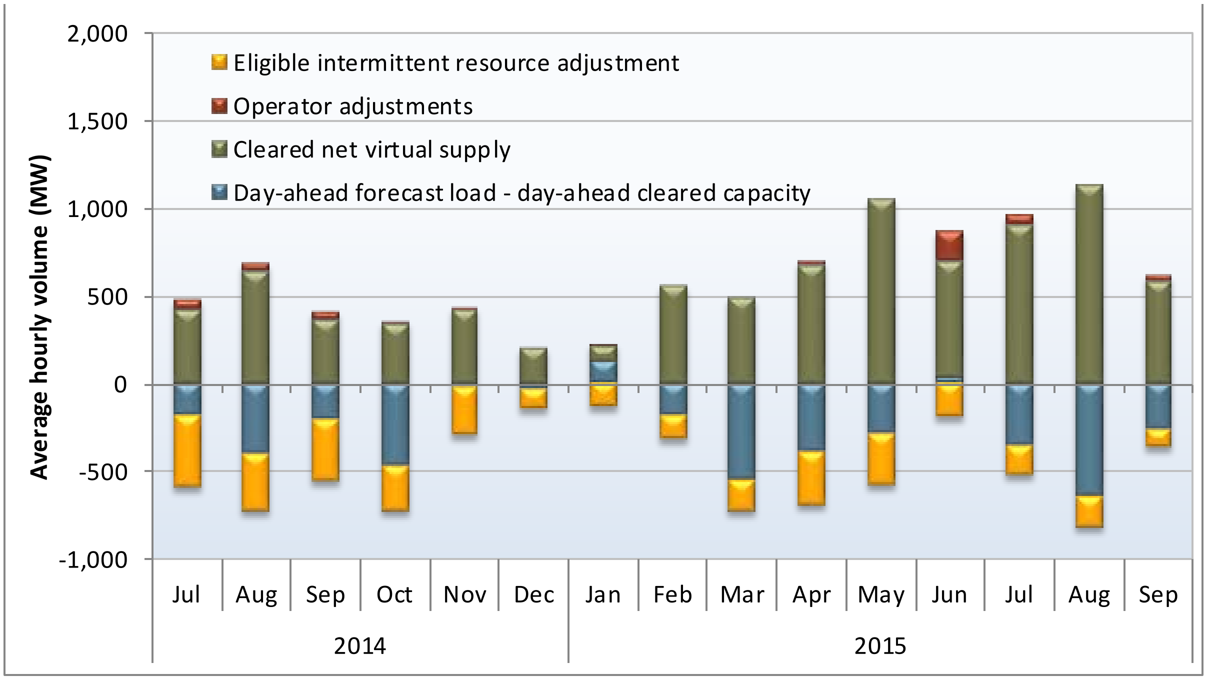
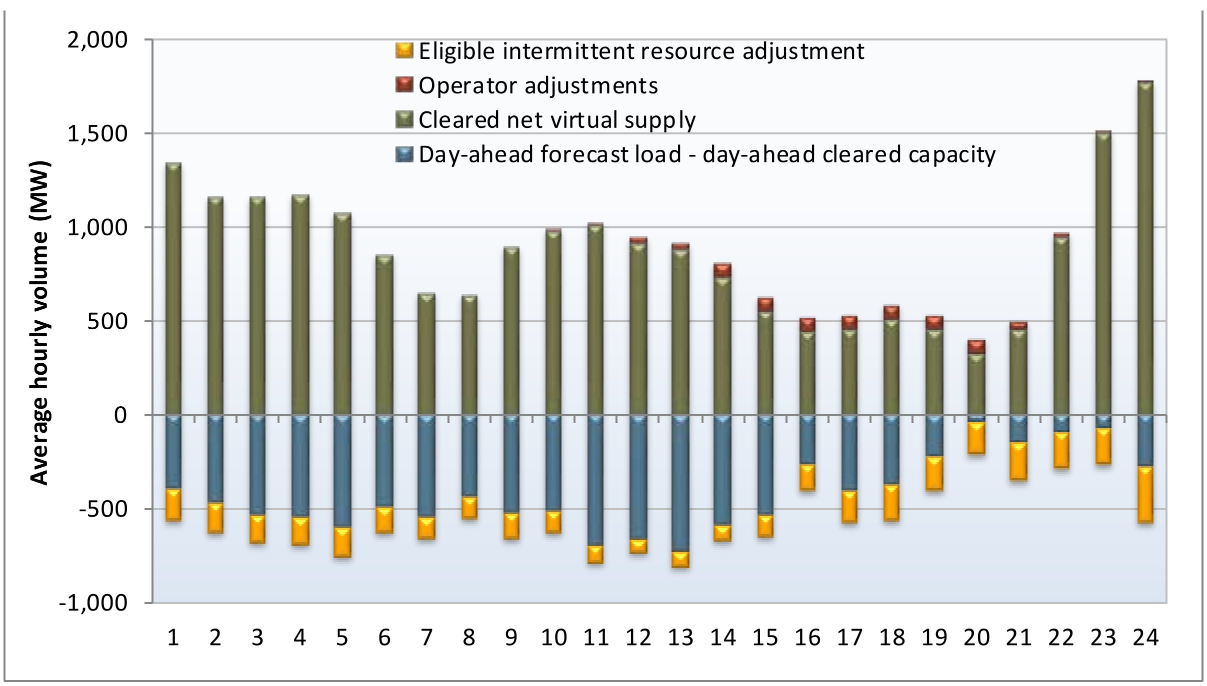


Figure 1.11 Average hourly determinants of residual unit commitment procurement (July – September)



1.6 Bid cost recovery

Estimated bid cost recovery payments for the third quarter totaled about $31 million. This is an increase when compared to about $26 million in the second quarter of 2015 and about $20 million in the third quarter of 2014. Much of the increase can be attributed to significantly higher residual unit commitment bid cost recovery payments than in earlier periods. For instance, residual unit commitment bid cost recovery in the third quarter of 2014 was less than $750,000, whereas in the third quarter of 2015 it totaled about $9.7 million. Real-time bid cost recovery also increased, from around $13 million in the third quarter of 2014 to around $16 million in the third quarter of 2015.

As seen in Figure 1.13, after netting against real-time revenues in the third quarter of 2015, long-start resources received the largest share of the residual unit commitment bid cost recovery payments ($7.3 million) while short-start resources received $2.4 million. These payments were highest in July with long-start receiving $4.2 million and short-start receiving $1.1 million. As noted in Section 1.5, high volumes of net virtual supply combined with periods of high loads in July and August caused the residual unit commitment process to commit more resources. While most of the resources committed by the residual unit commitment were short-start resources, which do not receive binding commitment instructions, most of the residual unit commitment bid cost recovery in the third quarter was associated with the commitment of long-start resources. In previous periods, most residual unit commitment bid cost recovery was from short-start resources (see Figure 1.13).

Figure 1.12 Monthly bid cost recovery payments

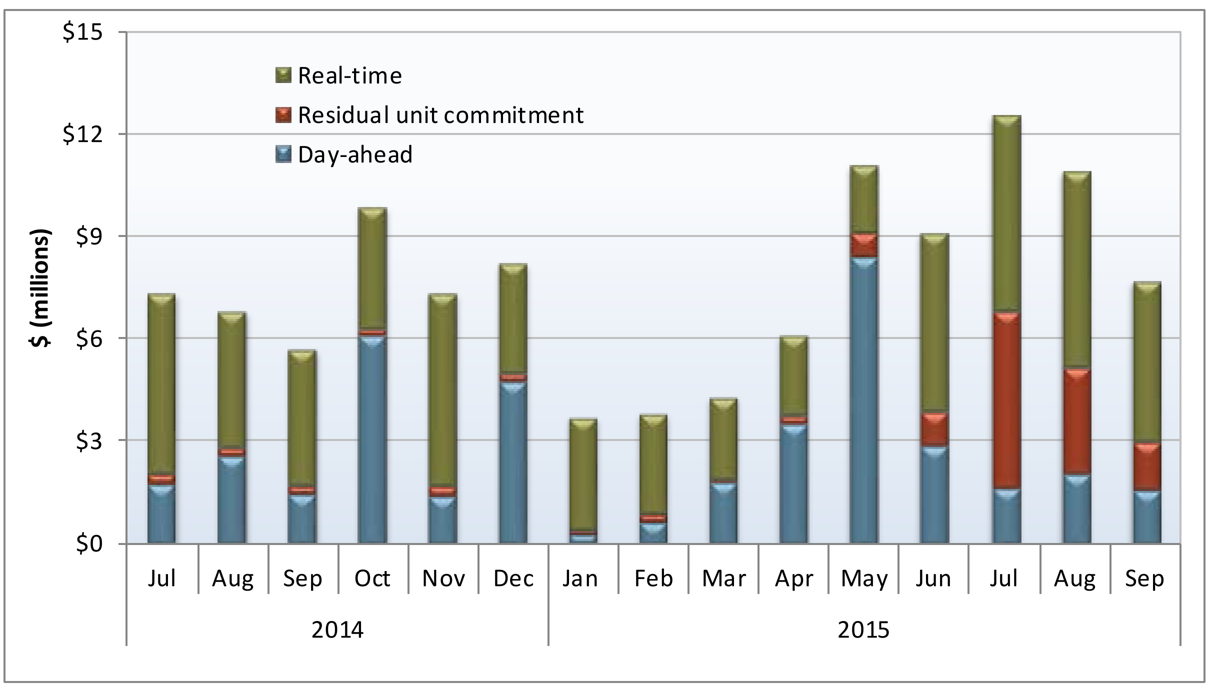
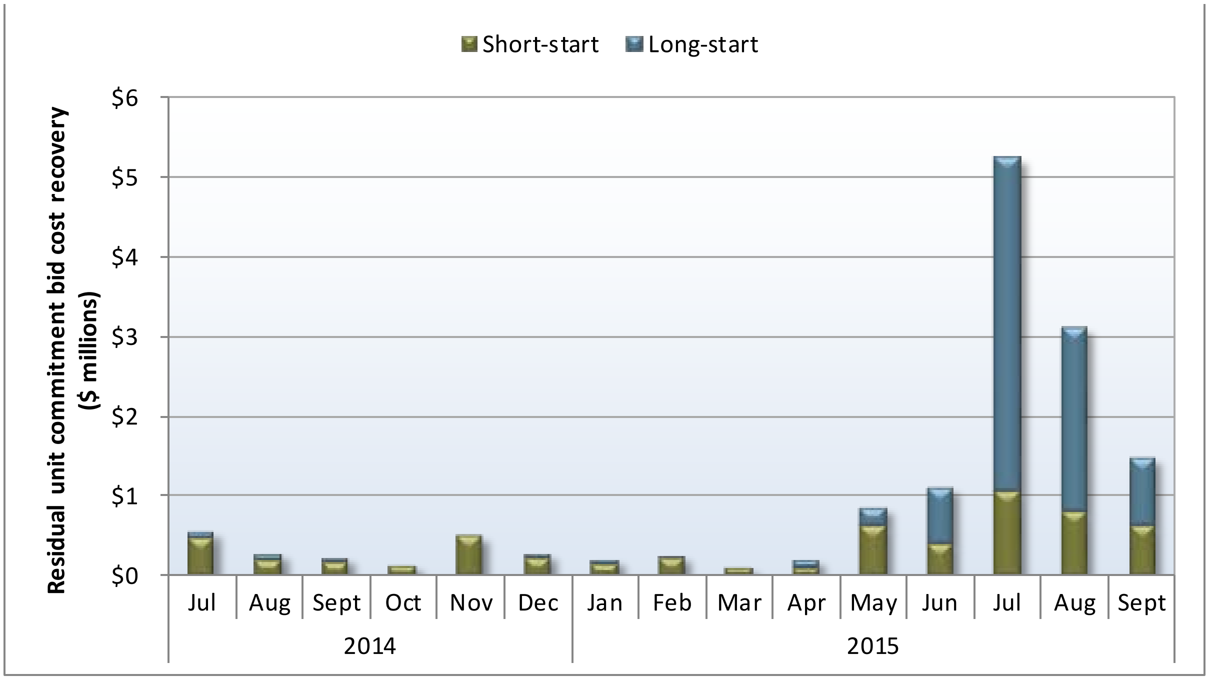


Figure 1.13 Residual unit commitment bid cost recovery payments by commitment type



1.7 Convergence bidding

Participants engaging in convergence bidding continued to earn positive returns in the third quarter. The net revenues from the market in these three months were about $9.7 million. Virtual supply generated net revenues of about $16.7 million while virtual demand accounted for approximately $7 million in net payments to the market. The total payment to convergence bidders fell slightly, to about $5 million, after taking into account virtual bidding bid cost recovery charges of $4.7 million.

Offsetting virtual demand with supply bids at different locations is designed to profit from higher anticipated congestion between these locations in the real-time market. This type of offsetting bid represented about 53 percent of all accepted virtual bids in the third quarter, similar to the level in the previous quarter.

Total hourly trading volumes increased in the third quarter to about 3,500 MW from 3,100 MW in the previous quarter. Virtual supply averaged around 2,180 MW while virtual demand averaged around 1,300 MW during each hour of the quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 880 MW on average, an increase from 800 MW of net virtual supply in the previous quarter.

Net revenues for most of the third quarter were positive from net virtual supply positions and negative from net virtual demand positions as prices were generally higher in the day-ahead market than the 15-minute market.[18]

[18] For additional background please refer to Section 3.6 Convergence bidding in the *Q4 2014 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2014FourthQuarterReport_MarketIssuesandPerformance_March2015.pdf.

1.7.1 Convergence bidding trends

Total hourly trading volumes increased in the third quarter to about 3,500 MW from 3,100 MW in the previous quarter. These volumes had remained relatively stable for the last few quarters. On average, about 61 percent of virtual supply and demand bids offered into the market cleared in the third quarter, which is up from 47 percent in the second quarter.

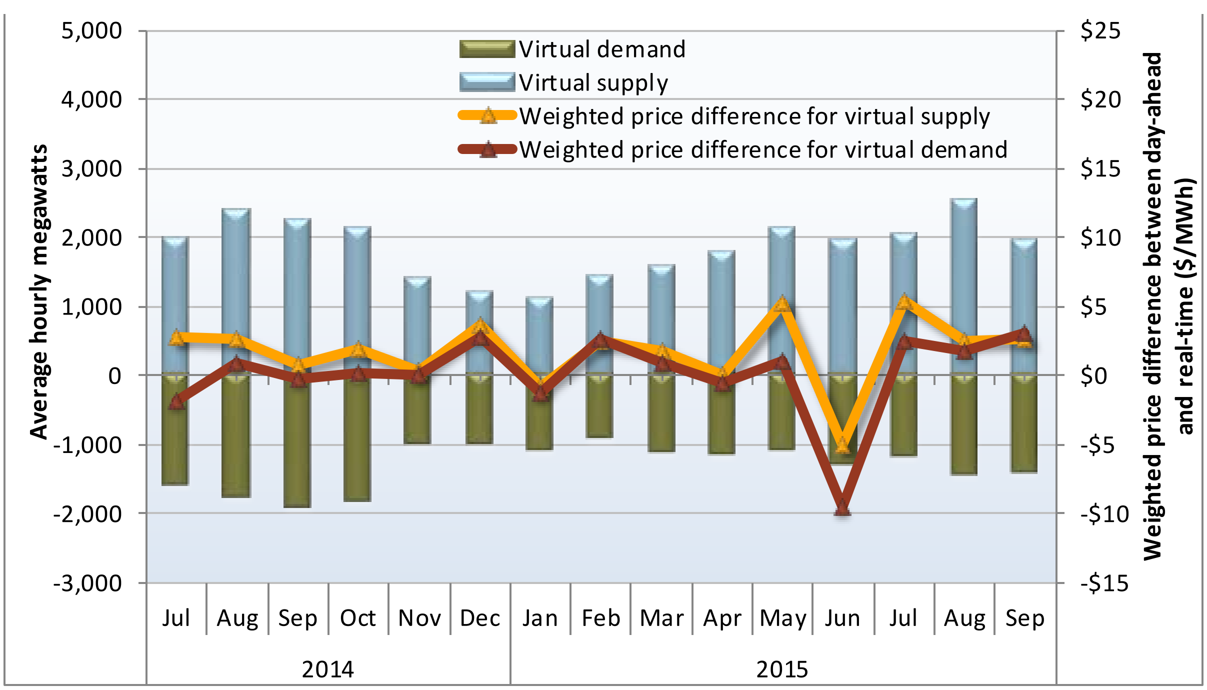
Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 880 MW on average, which increased from 800 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours, by about 680 MW and 1,260 MW, respectively. For the quarter, net cleared virtual supply exceeded net cleared virtual demand in all hours. The highest net cleared virtual supply hour was hour ending 24 at about 1,800 MW.

Consistency of price differences and volumes

Convergence bidding is designed to align 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. Averaging for the quarter, net convergence bidding volumes were very consistent with price differences between the day-ahead and real-time markets in all 24 hours. By month for the quarter, net convergence bidding volumes were consistent with price differences between the day-ahead and real-time markets for an average of 24, 24 and 21 hours for July, August and September, respectively. Compared to the previous quarter, net convergence bidding volumes were increasingly more consistent with price differences between the two markets.

Figure 1.14 compares cleared convergence bidding volumes with the volume-weighted average price difference where the 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 locations.

Figure 1.14 Convergence bidding volumes and weighted price differences



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

Virtual demand volumes for all three months of the quarter were inconsistent with weighted average price differences for the hours in which virtual demand cleared the market and, thus, were not profitable on average.

The yellow line in Figure 1.16 represents the difference between the day-ahead price paid to virtual supply and the real-time market price at which virtual supply positions are liquidated, weighted by cleared virtual supply bids by time interval and location. Virtual supply positions in the first quarter were, on average, profitable in all three months.

Offsetting virtual supply and demand bids

Market participants can 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 locations during the same hour. These virtual demand and supply bids offset each other in terms of system energy and are not exposed to bid cost recovery settlement charges. 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 differences between the day-ahead and real-time markets.

The majority of cleared virtual bids in the third quarter were offsetting bids. Offsetting virtual positions accounted for an average of about 930 MW of virtual demand offset by 930 MW of virtual supply in each hour of the quarter. These offsetting bids represent about 53 percent of all cleared virtual bids in the third quarter, which is about the same as in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion.

1.7.2 Convergence bidding revenues

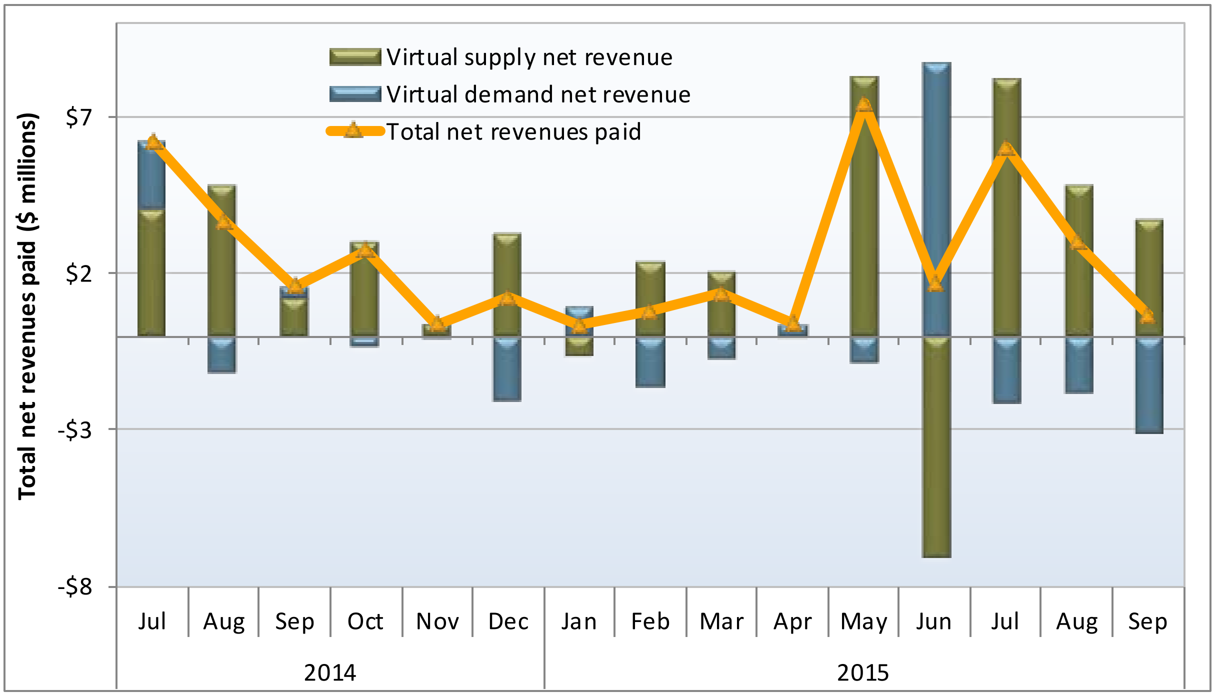
This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders in the third quarter. Similar to the previous quarter, convergence bidding participants earned positive revenue. In the third quarter, net revenues were about $9.7 million from revenue collected on both virtual supply and demand positions.

Figure 1.15 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- The net revenues from the market were about $9.7 million in the third quarter, compared to about $11.5 million in the same quarter in 2014, and $9.5 million in the previous quarter.
- Virtual supply revenues were most profitable in July as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply accounted for net payments of about $16.7 million during the quarter.
- Virtual demand revenues were negative in all three months of the quarter. In total, virtual demand accounted for around $7 million in net payments to the market for the quarter.

- Convergence bidders were paid about $5 million after subtracting virtual bidding bid cost recovery charges of $4.7 million for the quarter.[19,20] These costs were about $2.5 million, $1.7 million and $0.5 million in July, August and September, respectively.

Figure 1.15 Total monthly net revenues paid from convergence bidding



Net revenues and volumes by participant type

Table 1.6 compares the distribution of convergence bidding cleared volumes and net revenues in millions of dollars among different groups of convergence bidding participants.[21] As shown in Table 1.6, financial entities represent the largest segment of the virtual bidding market in terms of volume, accounting for about 58 percent of volumes and about 52 percent of settlement dollars. Marketers represent about 22 percent of the trading volumes and 23 percent of the settlement dollars. Generation owners and load-serving entities represent a slightly smaller segment of the virtual market in terms of volumes (about 20 percent), but a larger segment of the settlements portion than marketers (25 percent).

[19] Further detail on bid cost recovery and convergence bidding can be found here: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

[20] The Business Practice Manual configuration guide has been updated for CC 6806 Day Ahead Residual Unit Commitment Tier 1 Allocation to ensure that the RUC Obligation does not receive an excess RUC TIER 1 charge or payment. For additional information, refer to BPM Change Management Proposed Revision Request posted on September 25.

[21] DMM has defined financial entities as participants who own no physical power and participate in the convergence bidding and congestion revenue rights markets only. Physical generation and load are represented by participants that primarily participate in the ISO markets 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.

Table 1.6 Convergence bidding volumes and revenues by participant type (July – September)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	951	1,078	2,029	-$5.25	$10.31	$5.06
Marketer	291	473	763	-$1.09	$3.29	$2.21
Physical load	6	369	376	-$0.10	$1.83	$1.74
Physical generation	54	257	311	-$0.55	$1.25	$0.70
Total	**1,302**	**2,177**	**3,479**	**-$7.0**	**$16.7**	**$9.7**

Virtual bid cost recovery charges

Virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.[22] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up, minimum load, transition, and energy bid costs.[23]

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[24]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[25] In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.

[22] If physical generation resources clearing the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecasted demand. Convergence bidding increases unit commitment requirements to ensure sufficient generation in real time when the net position is virtual supply. The opposite is true when virtual demand exceeds virtual supply.

[23] Generating units, pumped-storage units, or resource-specific system resources are eligible for receiving bid cost recovery payments.

[24] Both charge codes are calculated by hour and charged on a daily basis.

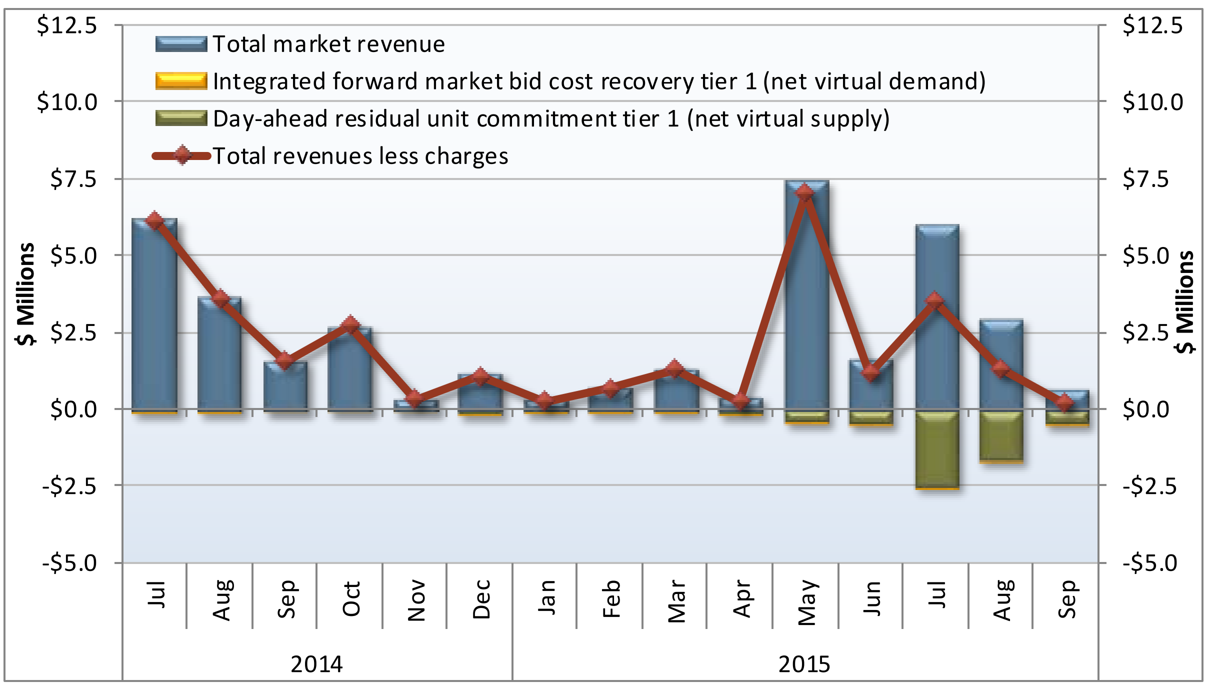
[25] Total integrated forward market (IFM) load and convergence bidding entities with a net virtual demand position may be charged an IFM Tier 1 uplift charge. This is triggered when the system-wide virtual demand is positive. Market participants with portfolios that clear with positive net virtual demand are charged. Market participants will not be charged if physical demand plus virtual demand minus virtual supply is equal to or less than measured demand. Specifically, the uplift obligation for virtual demand is based on how much additional unit commitment was driven by net virtual demand that resulted in the integrated forward market clearing above what was needed to satisfy measured demand. Physical load and virtual demand pay the same IFM uplift rate. The rate is calculated on an hourly basis and charged daily. For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply.[26] In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

Market participants with net virtual supply, which contributes to residual unit commitment costs, share in the associated bid cost recovery charges. Day-ahead residual commitment costs associated with net virtual supply increased dramatically. Similar to the previous quarter, the integrated forward market bid cost recovery costs associated with net virtual demand remained low in the third quarter.

Figure 1.16 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. The total convergence bidding bid cost recovery costs for the third quarter were close to $4.7 million, a large increase from $1.1 million in the previous quarter. This increase is directly related to the increase in residual unit commitment levels and related bid cost recovery payments (see Section 1.5 and Section 1.6).

Figure 1.16 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1



[26] There are two payments associated with the day-ahead residual unit commitment. One is the residual unit commitment availability payment at the residual unit commitment price, and the other is residual unit commitment bid cost recovery. During the day-ahead market, if the scheduled demand is less than the forecast, residual unit commitment availability is procured to ensure that enough committed capacity is available and online to meet the forecasted demand. Awarded capacity is paid at the residual price. The residual unit commitment bid cost recovery uplift obligation is allocated when system-wide net virtual supply is positive. The virtual supply obligation to pay a residual unit commitment bid cost recovery tier 1 uplift is based on the pro-rata share of the total obligation as determined by market participants' total net virtual supply awards. Allocation of residual unit commitment compensation costs is calculated by hour and charged by the day. For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

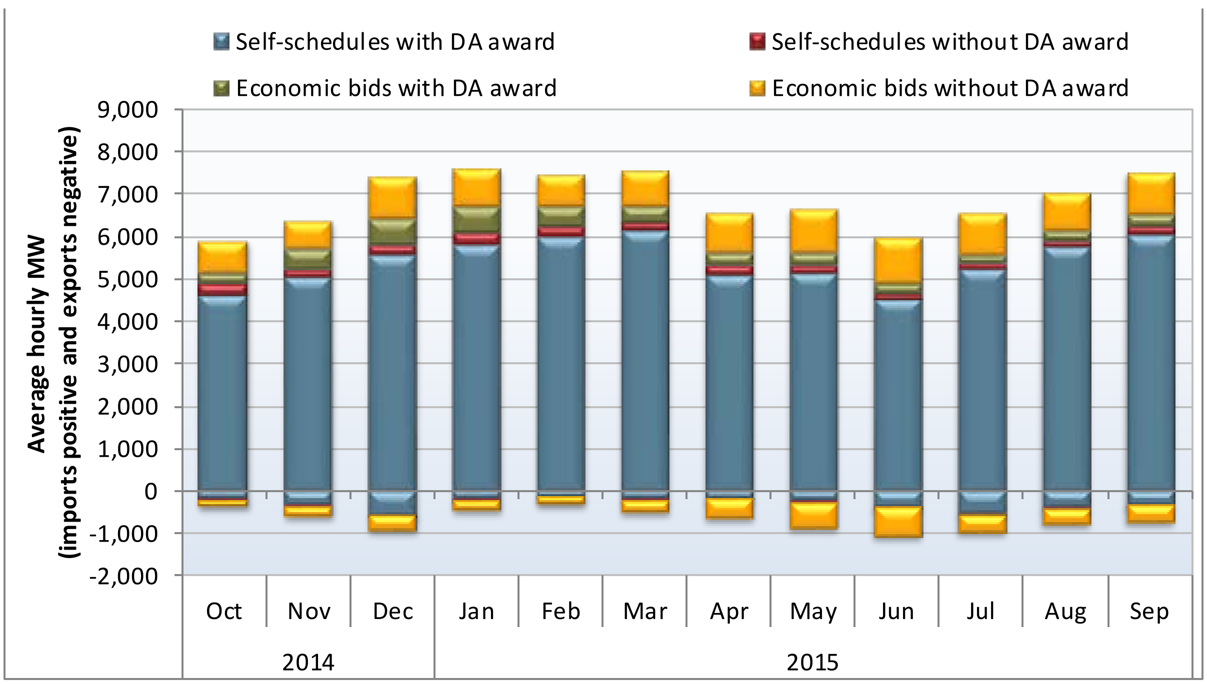
2 Special issues

2.1 Inter-tie bidding and scheduling

After implementing 15-minute scheduling on the inter-ties in May 2014, there was a significant decrease in the amount of inter-tie bids offered into the real-time market as well as an increase in the volume of self-scheduled inter-tie transactions. Overall, this trend held into 2015 and the third quarter.[27]

Figure 2.1 shows the hourly average level of economic bids and self-schedules for imports and exports in the real-time market. The figure further indicates whether the bids and self-schedules came from resources with or without day-ahead awards.[28] As seen in this figure, self-schedules from resources with day-ahead awards accounted for most of the real-time activity on the inter-ties. In the third quarter, the percent of bids that were self-scheduled (with or without day-ahead award) increased to around 83 percent for imports and 47 percent for exports. Of the economic bids, about 82 percent of import bids and 97 percent of export bids were without day-ahead awards. Figure 2.1 also shows that the total volume of import bids and self-schedules increased compared to the second quarter, whereas the total amount of export bids and self-schedules decreased.

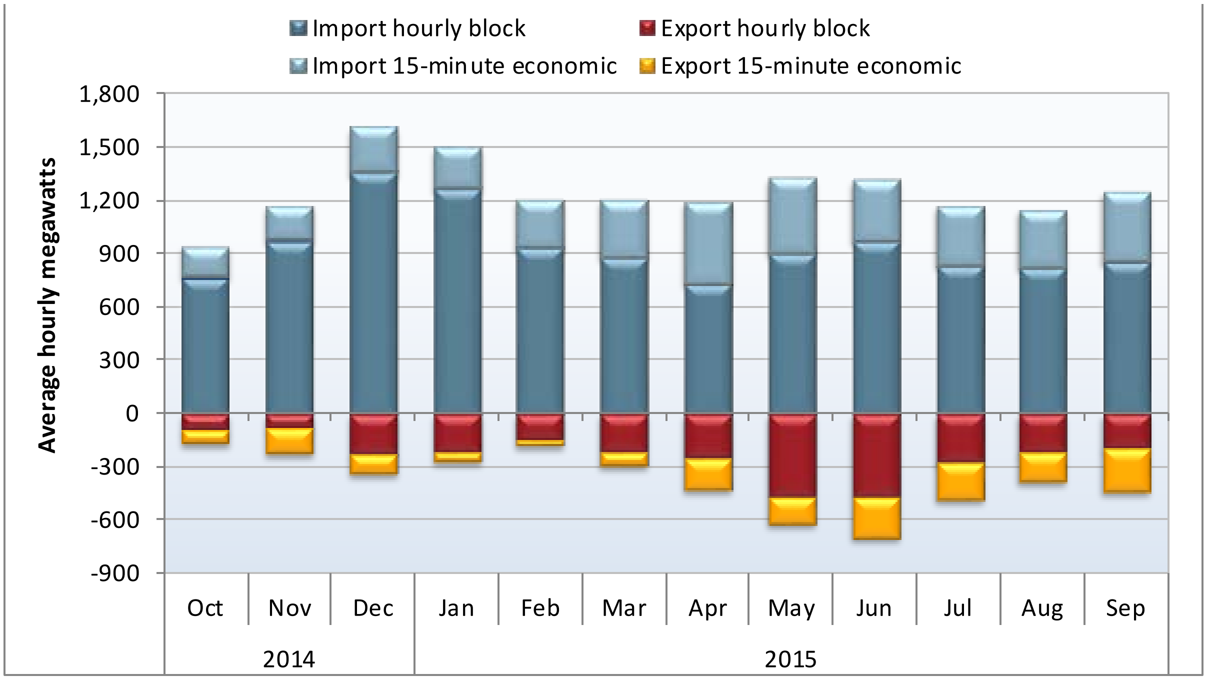
Figure 2.1 Volume of self-scheduled and economic import and export bids in the real-time market



[27] For a comparison between the periods before and after May 2014, see the *Q2 2015 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2015_SecondQuarterReport-MarketIssues_Performance-August2015.pdf.

[28] The classification is made by MW at the resource level. For example, if a resource has a 10 MW award from the day-ahead market and places a 20 MW economic bid in the real-time market, then 10 MW is considered to be with a day-ahead award and 10 MW is considered without a day-ahead award.

Figure 2.2 Economic import and export bids by bidding option



Most of the real-time economic bids on the inter-ties remained in the hour-ahead market, as shown in Figure 2.2. Around 70 percent of economic import bids were hourly block bids in the third quarter, a slight increase from 68 percent in the second quarter. The percent of hourly block export bids decreased from 67 percent in the second quarter to 52 percent in the third quarter.[29] The remaining 30 percent of economic import bids and 48 percent of economic export bids were 15-minute economic bids.

The volume of 15-minute dispatchable import bids decreased by 14 percent compared to the second quarter, averaging 355 MW each hour in the third quarter. Conversely, 15-minute dispatchable economic export bids increased by 10 percent to an average of 210 MW for the same period. The volume of 15-minute economic export bids in the third quarter was the highest quarterly value since 15-minute import bidding began in May 2014.

Figure 2.3 shows the hourly average amount of 15-minute dispatchable economic import and export bids by inter-tie, with each color representing a different scheduling coordinator. As in previous quarters, these bids were concentrated on three inter-ties and submitted by a small number of participants. The majority of these participants were external balancing authority areas.

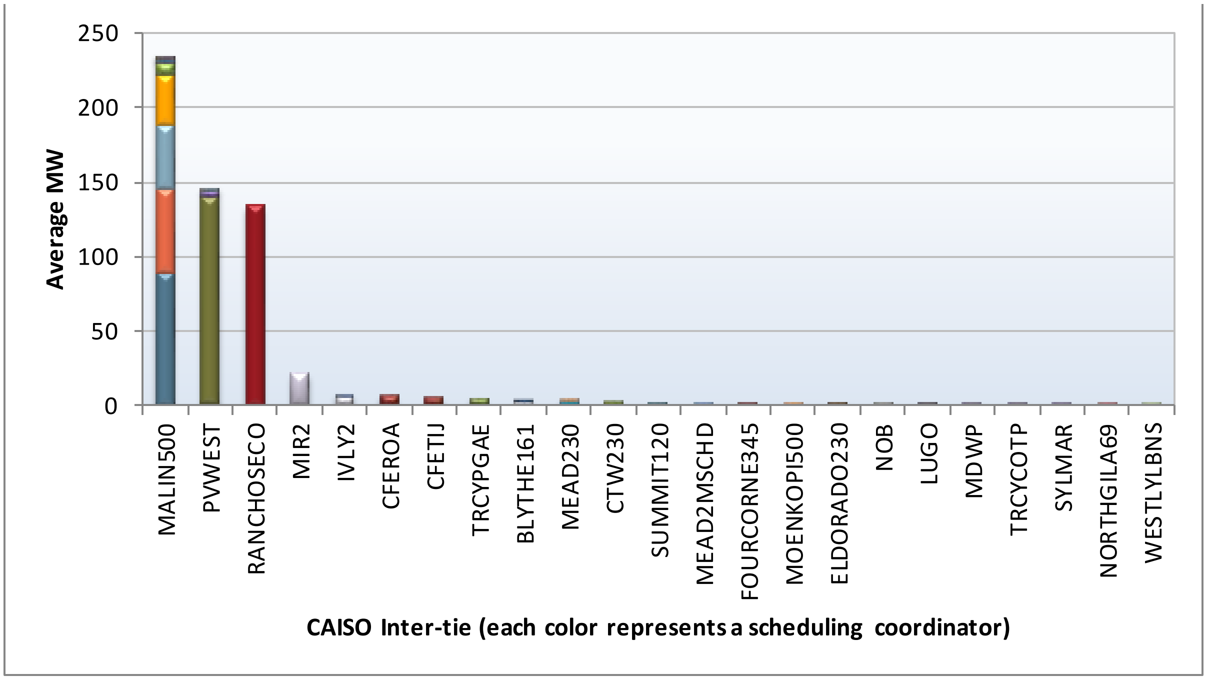
DMM published a report in April discussing how the lack of liquidity on the inter-ties in the 15-minute market would be problematic if convergence bidding on the inter-ties were to be reintroduced.[30] FERC

[29] As with previous quarters, participants seldom used the hourly economic bid block option with a single intra-hour economic schedule change on the inter-ties.

[30] The DMM report on potential issues with implementing convergence bidding on the inter-ties can be found here: http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf. The analysis in the special report included bids by tie-generators, which are excluded from the analysis in this section.

issued an order in late September requiring the ISO to remove tariff provisions that provided for reinstatement of convergence bids at inter-ties.[31]

Figure 2.3 15-minute dispatchable economic bids by inter-tie and scheduling coordinator (July through September)



2.2 Flexible ramping constraint performance

This section highlights the performance of the flexible ramping constraint over the last quarter. Key trends include the following:

- Flexible ramping costs were around $1.3 million in the third quarter, up from around $700,000 in the previous quarter.
- Most payments occurred during evening peak hours. Natural gas-fired capacity accounted for about 39 percent of these payments with hydro-electric capacity accounting for 58 percent.
- The flexible ramping requirement was, on average, set to 448 MW in the ISO, 113 MW in PacifiCorp East, and 84 MW in PacifiCorp West.

Background

The ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute market in December 2011.[32] The constraint is applied to internal generation, dynamic inter-

[31] For further details see: http://www.ferc.gov/CalendarFiles/20150925164451-ER15-1451-000.pdf.

[32] The flexible ramping constraint is also binding in the second, but not the first, interval of the 5-minute real-time market.

ties and proxy demand response resources within the ISO balancing area, as well as the EIM balancing areas beginning in November 2014.

If sufficient flexible upward ramping capacity is on line, the ISO software 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 software 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 the 15-minute market. A procurement shortfall of flexible ramping capacity will occur when there is a shortage of available supply bids to meet the flexible ramping requirement.[33]

Flexible ramping constraint requirement

The ISO implemented a tool to automatically calculate the flexible ramping requirement in both the ISO and PacifiCorp balancing areas in March 2015. The tool determines the flexible ramping requirement independently for each 15-minute interval based on the observed ramping need for that interval in the preceding 40 instances.[34] The requirements are bounded within predefined lower and upper limits. Because the requirement is based on relatively few observations, and because each interval is considered independently, the resulting ramping requirement has been highly volatile and was often set by either the lower or upper bound.[35]

Table 2.1 through Table 2.3 show the average amount, range and volatility of the flexible ramping constraint requirements by month for the ISO and PacifiCorp balancing areas. Volatility is measured as the standard deviation of the percent change in the requirements between intervals. A higher volatility implies more frequent and/or larger changes in the requirement from one interval to the next. Further, the tables show the percent of intervals when the requirement was equal to the lower or upper bounds.

As shown in these tables, the volatility of the flexible ramping requirements increased significantly after implementing the balancing area ramping requirement tool. In the third quarter, the requirements were more often equal to either the upper or lower bounds, which resulted in a lower level of volatility compared to the second quarter.[36] However, with the exception of PacifiCorp West in September, the volatility remained significantly higher than prior to implementation of the tool.

The tables further show that the average requirement was higher in the third quarter compared to the second quarter. This was partly because the lower bounds of the requirements were increased at the

[33] The penalty price associated with procurement shortfalls was set to $247 before January 15, 2015. Beginning January 15, the penalty price is now set to $60. For more information, see: http://www.caiso.com/Documents/Dec18_2014_OrderAcceptingFlexibleRampingConstraintParameterAmendment_ER15-50.pdf.

[34] Specifically, it sets the requirement at the 95th percentile of the 40 observations. Weekend days are considered as separate observations from weekdays.

[35] For a more detailed discussion about the implementation of the tool and the resulting increase in ramping requirement volatility see the *Q2 2015 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2015_SecondQuarterReport-MarketIssues_Performance-August2015.pdf.

[36] This may in part be related to a change in the calculation that was implemented in the third quarter that made the calculation of the ramping requirement the direct difference between the ramping needs in the 15-minute and 5-minute markets.

end of June. The average requirement for the third quarter increased to 448 MW in the ISO, 113 MW in PacifiCorp East and 84 MW in PacifiCorp West.

Table 2.1 Flexible ramping requirement and volatility (ISO)

	Requirement (MW)				Percent of intervals		
Month	Avg	Min	Max	Volatility	Req = Lower bound	Req = Upper bound	Req = bounds
Jan	373	300	450	4%			
Feb	373	300	450	4%			
Mar	369	100	500	19%			
Apr	270	80	500	88%	36%	27%	64%
May	300	80	500	71%	36%	41%	77%
Jun	350	80	500	28%	38%	48%	86%
Jul	428	300	500	11%	34%	63%	97%
Aug	449	300	500	13%	20%	69%	89%
Sep	467	300	500	16%	11%	74%	85%

Table 2.2 Flexible ramping requirement and volatility (PacifiCorp East)

	Requirement (MW)				Percent of intervals		
Month	Avg	Min	Max	Volatility	Req = Lower bound	Req = Upper bound	Req = bounds
Jan	33	30	40	5%			
Feb	33	30	40	5%			
Mar	33	20	150	28%			
Apr	44	20	150	102%	55%	12%	67%
May	39	20	100	98%	62%	14%	76%
Jun	63	20	150	70%	66%	7%	73%
Jul	87	80	150	22%	82%	5%	87%
Aug	112	80	150	17%	45%	35%	80%
Sep	139	80	150	12%	8%	68%	75%

Table 2.3 Flexible ramping requirement and volatility (PacifiCorp West)

Month	Requirement (MW) Avg	Min	Max	Volatility	Percent of intervals Req = Lower bound	Req = Upper bound	Req = bounds
Jan	26	25	30	3%			
Feb	26	25	30	3%			
Mar	27	20	100	25%			
Apr	47	10	100	116%	18%	55%	73%
May	32	10	50	141%	36%	45%	81%
Jun	54	10	100	73%	49%	18%	67%
Jul	69	60	100	24%	68%	16%	84%
Aug	86	60	100	19%	29%	58%	86%
Sep	97	60	100	2%	7%	92%	99%

Flexible ramping procurement costs

Total payments for flexible ramping resources in the third quarter were around $1.3 million, up from around $700,000 in the previous quarter.[37] Table 2.4 provides a review of monthly flexible ramping constraint activity in the 15-minute market.[38] The table highlights the following:

- The flexible ramping constraint was binding in the ISO area in around 4 percent of intervals in the third quarter, down from around 6 percent in the second quarter.
- The frequency of procurement shortfalls in the ISO area decreased to 0.3 percent of all 15-minute intervals compared to 0.8 percent in the second quarter.
- The average shadow price when the flexible ramping constraint was binding in the ISO area was about $15/MWh, a slight decrease from about $18/MWh in the second quarter.

Most payments for ramping capacity occurred during the evening peak hours. Figure 2.4 shows the hourly flexible ramping payment by technology type during the third quarter. As shown in the figure, the highest payment periods were in hours ending 17 through 21. Natural gas-fired capacity accounted for about 39 percent of these payments with hydro-electric capacity accounting for 58 percent.

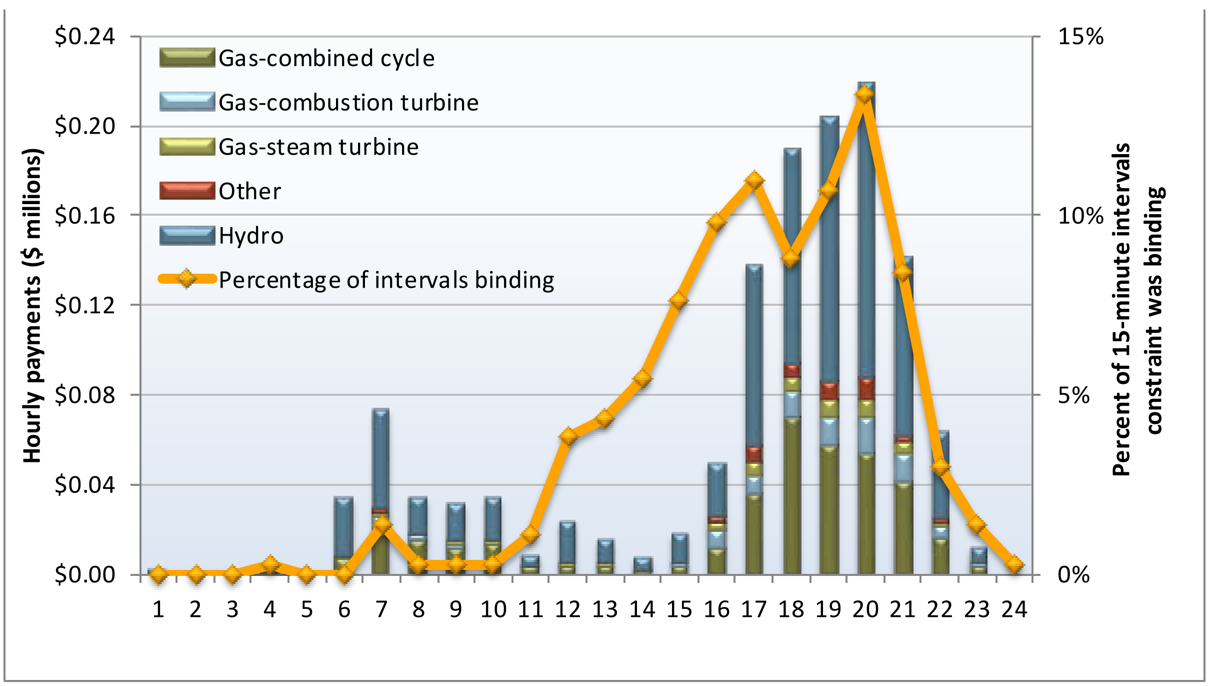
[37] There are also secondary costs, such as those related to bid cost recovery payments to cover the commitment costs of the units committed by the constraint and additional ancillary services payments. Assessment of these costs is complex and beyond the scope of this analysis.

[38] DMM had problems with data availability between October 16 and October 30, 2014, and thus did not include the data from that period in the calculation. In addition, likely due to the incorrect application of the flexible ramping credit, the flexible ramping constraint was never binding in December and January.

Table 2.4 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)
2014	Oct	$0.42	4%	0.4%	$41.84
2014	Nov	$0.19	1%	0.2%	$74.48
2014	Dec	$0.02	0%	0.0%	$0.00
2015	Jan	$0.04	0%	0.0%	$0.00
2015	Feb	$0.10	6%	0.5%	$15.61
2015	Mar	$0.26	7%	1.3%	$26.15
2015	Apr	$0.32	8%	1.3%	$18.95
2015	May	$0.09	3%	0.2%	$13.86
2015	Jun	$0.36	6%	1.0%	$20.11
2015	Jul	$0.17	2%	0.2%	$12.35
2015	Aug	$0.45	4%	0.2%	$19.10
2015	Sep	$0.68	5%	0.4%	$13.68

Figure 2.4 Hourly flexible ramping constraint payments to generators (July – September)



3 Energy imbalance market

This section covers the energy imbalance market performance during the third quarter of 2015. Below are key observations and findings.

- Prices in the EIM during most intervals have been closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during some intervals energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand.
- The frequency of intervals in which the power balance constraint was relaxed remained at low levels for July and August in PacifiCorp East and PacifiCorp West for both the 5-minute and the 15-minute markets. This resulted in reasonably good convergence between the EIM price and the EIM price without price discovery in all four markets.
- There was a marked increase in power balance shortages in September in both the 15-minute and 5-minute markets in both PacifiCorp East and West. These increases generally caused an increase in price separation between the prices with and without price discovery, although differences continue to be significantly smaller than those observed at the beginning of this market.
- Higher flexible ramping requirements and a reduction of available ramping capacity due to generation outages resulted in a significant increase in flexible ramping constraint relaxations during September. The frequency of flexible ramping constraint relaxation was highest in September in both PacifiCorp East and West compared to all previous months.
- In both the 5-minute and the 15-minute markets EIM prices with and without discovery remained near or below estimated bilateral market price index levels during July and August. However, in September, due to the increase of intervals with constraint relaxations, the bilateral market price was between the adjusted EIM price and the PacifiCorp West price in the 5-minute market, and the bilateral market price was below the adjusted and unadjusted prices in both 15-minute markets. Prices converged fairly closely in the 5-minute PacifiCorp East market.

3.1 Background

The energy imbalance market became financially binding with its first participant on November 1, 2014. Balancing authority areas outside of the ISO balancing area can now voluntarily take part in the ISO's real-time market. The energy imbalance market is expected to achieve benefits for customers and facilitate integration of higher levels of renewable generation.[39]

The EIM includes both 15-minute and 5-minute financially binding schedules and settlement. Energy imbalances between 15-minute schedules and base (pre-market) schedules settle at the 15-minute market prices, and energy imbalances between 15-minute schedules and 5-minute schedules settle at 5-minute market prices.

[39] For more information see the quarterly benefits reports, which can be found here: http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

During the initial EIM implementation, the amount of capacity available through the market clearing process was restricted and imbalance needs were exaggerated in ways that are not reflective of actual economic and operational conditions. This caused the need to relax ramping and system energy balance constraints in the market software more frequently than expected to enable the market to clear. The factors contributing to the need for constraint relaxation and steps being taken to address these issues have been addressed by the ISO as noted in its reports submitted to FERC.[40] When relaxing the power balance constraint for an EIM area, prices could be set based on the $1,000/MWh penalty price for this constraint used in the pricing run of the market model.

After review, the ISO determined that many of these outcomes were inconsistent with actual conditions. Consequently, on November 13, 2014, the ISO filed with federal regulators special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.[41] These measures were approved by FERC on December 1. In addition, FERC ordered that the ISO and the Department of Market Monitoring provide reports every 30 days during the period of the waiver that outlines the issues driving the need for the EIM tariff waiver.[42] On March 16, 2015, FERC extended the waiver for an additional 90 days and, in addition, extended the reporting requirements.[43] On June 19, FERC further extended the waiver period and reporting requirements until the ISO can implement longer term solutions.[44]

3.2 Energy imbalance market performance

Prices have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during some intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand. Figure 3.1 and Figure 3.2 provide a monthly summary of the frequency of constraint relaxation (red and gold bars), average prices with (red line) and without price discovery (dashed red line), and bilateral market prices (blue line) for PacifiCorp East and PacifiCorp West, respectively.

Figure 3.1 and Figure 3.2 show relatively low frequencies of relaxation for the power balance constraint in the 15-minute market for both PacifiCorp East and West during July and August. In September, power balance constraint relaxation increased in both markets, though at lower levels relative to those observed when the market started.

Figure 3.1 and Figure 3.2 also show a progressive increase in the rates of flexible ramping constraint relaxation from July to August and from August to September in the 15-minute market in both regions. Despite the change in relaxation rates between the two months, these relaxation rates tended to be low relative to the beginning of EIM. The increase in flexible ramping constraint activity is likely to have occurred as a result of higher flexible ramping requirements and a reduction of available ramping

[40] The ISO *Energy Imbalance Market Pricing Waiver Reports* can be found here: http://www.caiso.com/rules/Pages/Regulatory/RegulatoryFilingsAndOrders.aspx.

[41] For further details, see http://www.caiso.com/Documents/Nov13_2014_PetitionWaiver_EIM_ER15-402.pdf.

[42] The DMM filings can be found here: http://www.caiso.com/rules/Pages/Regulatory/RegulatoryFilingsAndOrders.aspx.

[43] The March 16 order can be found here: http://www.caiso.com/Documents/Mar16_2015_OrderRejectingEIMTransitionPeriodPricingAmendment_ER15-861.pdf.

[44] The June 19 order can be found here: http://www.caiso.com/Documents/Jun19_2015_OrderGrantingMotion_Relief-EIMTransitionPeriodPrices_ER15-861_EL15-53.pdf.

capacity due to generation outages. The frequency of flexible ramping constraint relaxation was highest in September in both PacifiCorp East and West compared to all previous months.

Figure 3.1 and Figure 3.2 also show average daily prices in the 15-minute market with and without the special price discovery mechanism being applied to mitigate prices in PacifiCorp East and PacifiCorp West, respectively. In addition, the figures also provide a comparison of EIM prices to bilateral market price indices that estimate the prices that would have been used in the PacifiCorp areas prior to EIM implementation.[45]

The analysis shows that prices with and without the price discovery provision applied in EIM were very similar in both PacifiCorp East and West during July and August, which is largely driven by the low frequency of power balance constraint relaxations. In September, when the total number of power balance relaxations increased, the separation between the prices with and without price discovery increased but was less than in the months after EIM implementation. In July and August, EIM prices were lower than bilateral trading prices, but in September EIM prices were higher than bilateral trading prices in both markets.

Figure 3.3 and Figure 3.4 provide the same monthly summary for daily average prices in the 5-minute market. As shown in these figures, the need to relax the power balance constraint in the 5-minute market declined in the third quarter, and resulted in the lowest quarterly rate for relaxations for the year. However, similar to the results in the 15-minute market, September showed a marked increase in total intervals relaxed compared with the prior two months.

Similar to results in the 15-minute market, 5-minute prices in both regions were below bilateral trading hub prices during July and August. Additionally, because of the low frequency of power balance shortages and resulting convergence between adjusted and unadjusted prices, adjusted EIM prices were also lower than hub prices for both months in both regions. The higher number of power balance constraint relaxations in PacifiCorp West in September caused the prices without price discovery to be higher than the bilateral trading hub prices. In all other instances, 5-minute prices were lower than the bilateral trading hub prices.

As shown in Figure 3.1 through Figure 3.4, the price discovery mechanism approved under FERC's December 1 order has effectively mitigated the impact of constraint relaxation on market prices, particularly during the first six months after EIM launch in November 2014. Over the past few months, price discovery has been used less frequently because of the reduced frequency of power balance constraint relaxations.

[45] The bilateral market index represents a daily average of peak and off-peak prices for four major western trading hubs (California Oregon Border, Mid-Columbia, Palo Verde and Four Corners) using ICE data.

Figure 3.1 Frequency of constraint relaxation and average prices by month PacifiCorp East - 15-minute market

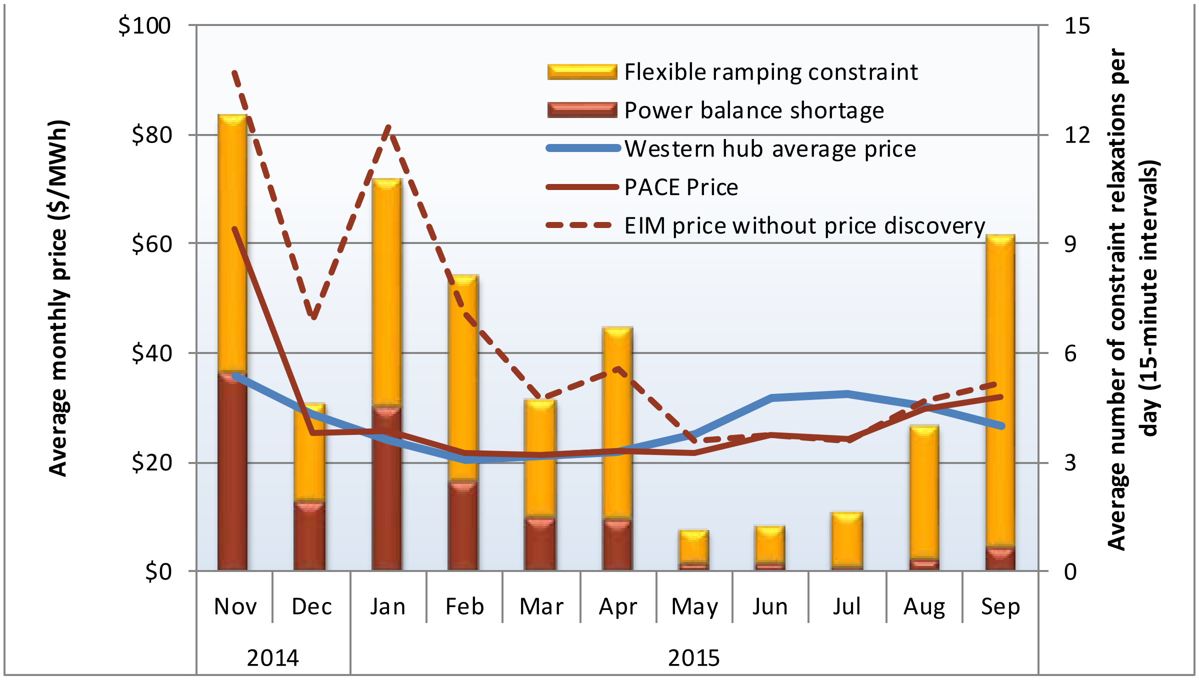


Figure 3.2 Frequency of constraint relaxation and average prices by month PacifiCorp West - 15-minute market

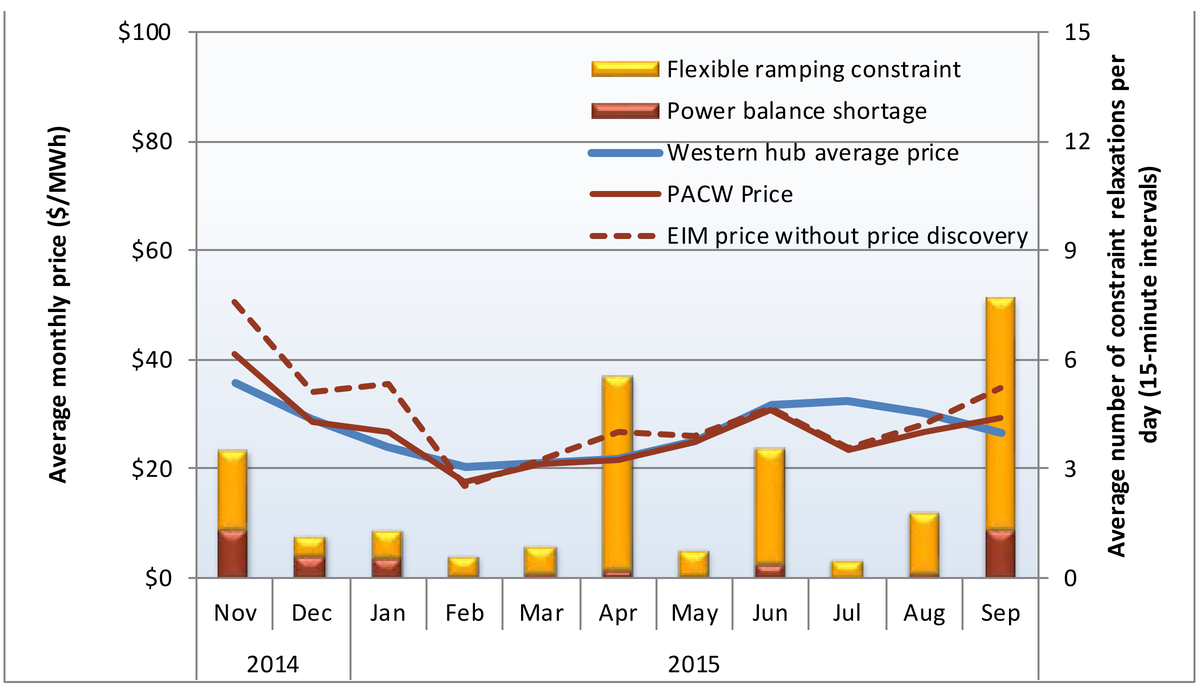


Figure 3.3 Frequency of constraint relaxation and average prices by month PacifiCorp East - 5-minute market

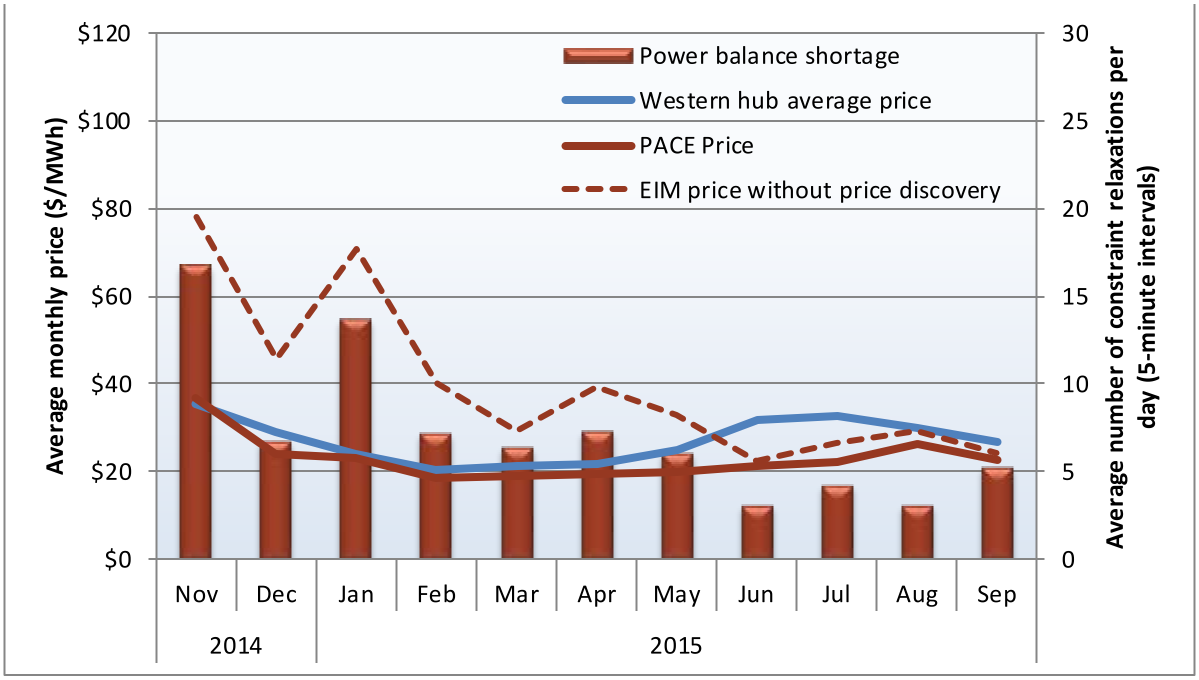


Figure 3.4 Frequency of constraint relaxation and average prices by month PacifiCorp West - 5-minute market