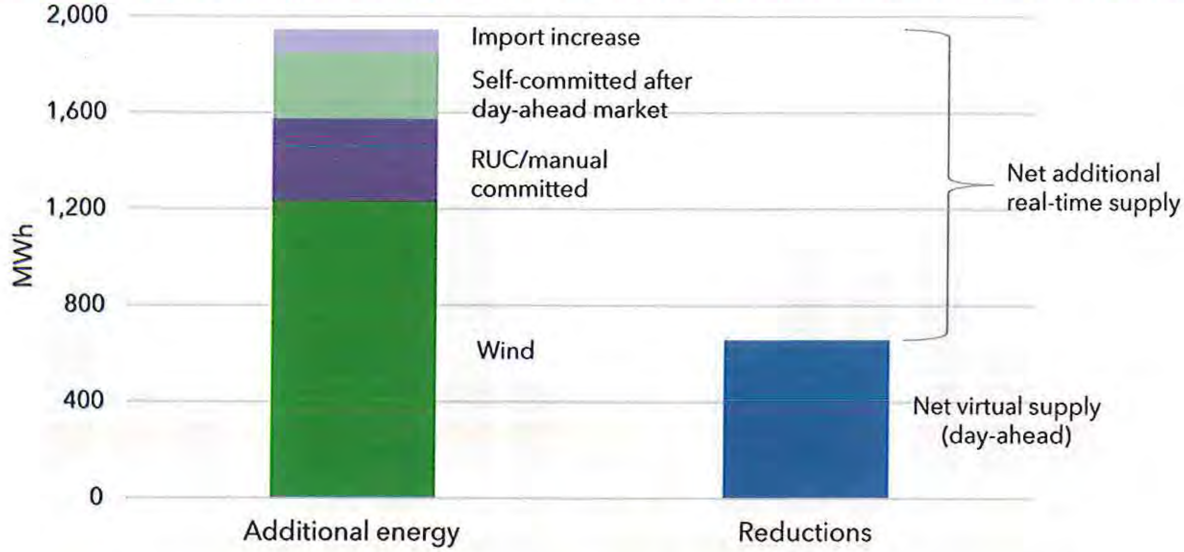
Figure 4-14 Average hourly real-time generation incremental to day-ahead market



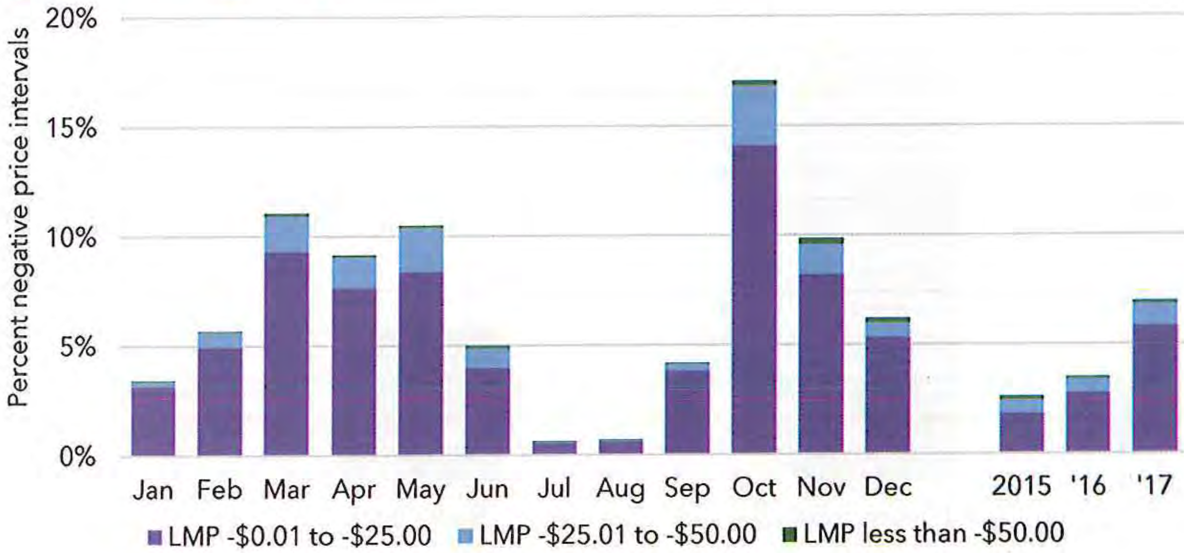
Wind generation had almost one-third of the incremental real-time generation in 2017, with an hourly average of 1,230 MW of additional generation in real time. Self-committed generation accounted for an additional 270 megawatts and reliability unit committed generation averaged about 345 MW. On average, SPP is a net exporter in both the day-ahead and real-time markets and sees an average hourly decrease of 98 MW in the real-time market compared to the day-ahead. This results in additional capacity committed in day-ahead not needed in real time. Net virtual positions helped to offset the additional generation, but only accounted for about 34 percent of the difference for the year.

4.1.6 NEGATIVE PRICES

With the prolific growth of wind generation in the SPP market, the number of intervals with negative prices continues to increase. In October 2017, 17 percent of all asset owner intervals[59] in the real-time market had prices below zero, as shown in Figure 4-15 below.

[59] Asset owner intervals are calculated as the number of asset owners serving load that are active in an interval. For example, if there 60 asset owners active in one five-minute interval throughout an entire 30 day month, the total asset owner intervals would be 518,400 for the month (60 asset owners * 288 intervals per day * 30 days).

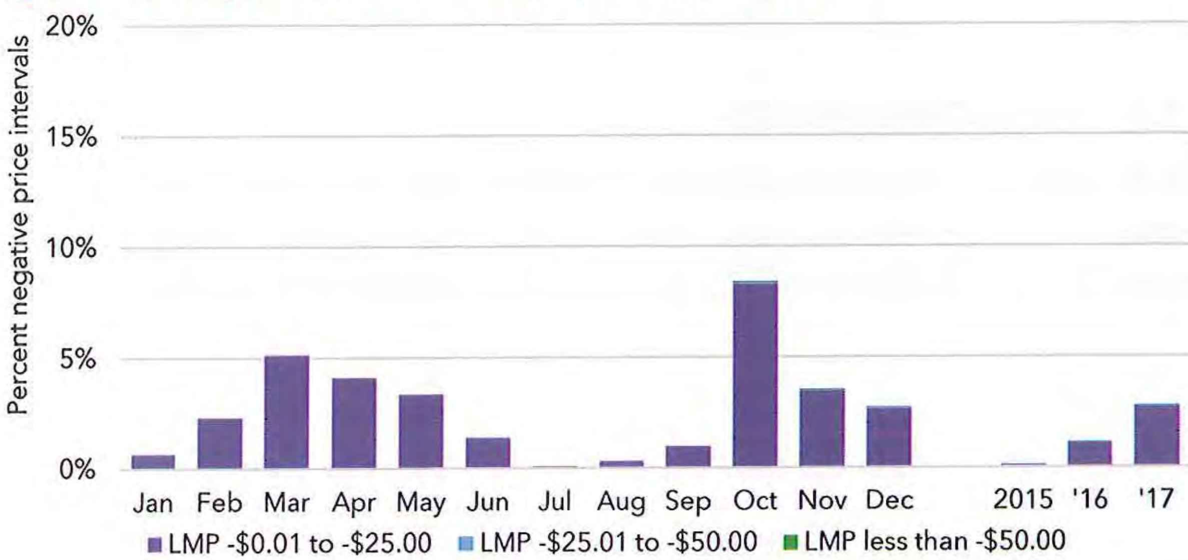
Figure 4-15 Negative price intervals, real time, monthly



On a year-to-year basis, the total percentage of negative price intervals in the real-time market has increased from 2.6 percent in 2015, to 3.5 percent in 2016, and to 7.0 percent in 2017.

While the same pattern holds in the day-ahead market (see Figure 4-16), the magnitude of negative price intervals in the day-ahead market is around half of the real-time market.

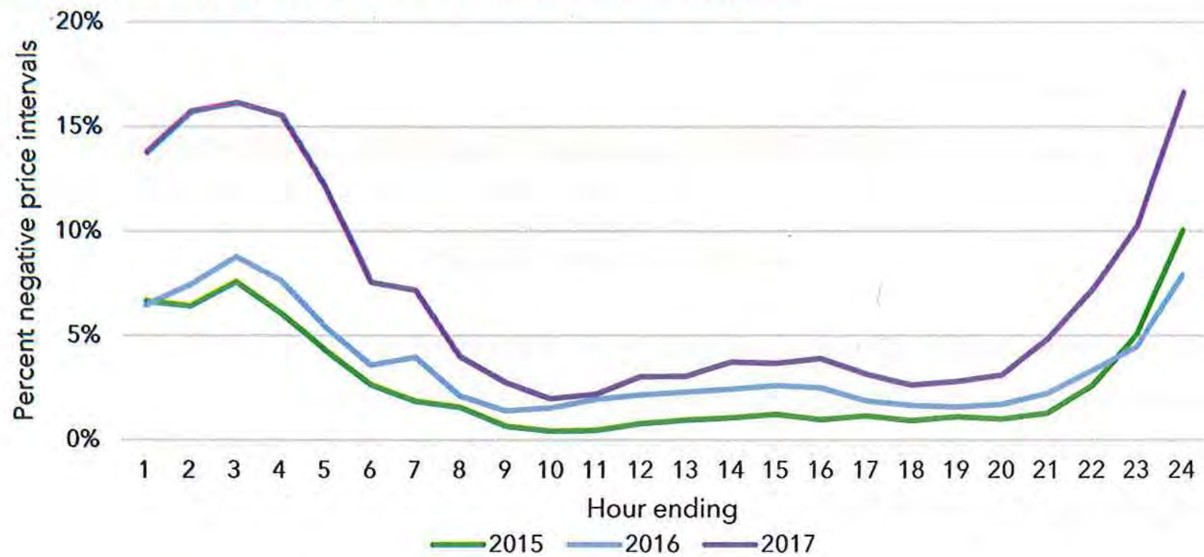
Figure 4-16 Negative price intervals, day-ahead, monthly



Note that negative prices in the day-ahead market are almost exclusively between -$0.01/MWh and -$25/MWh, where in the real-time market a sizable number of intervals have prices lower than -$25/MWh.

Additionally, occurrences of negative prices in the real-time market are most prevalent in the overnight, low-load hours as shown in Figure 4-17.

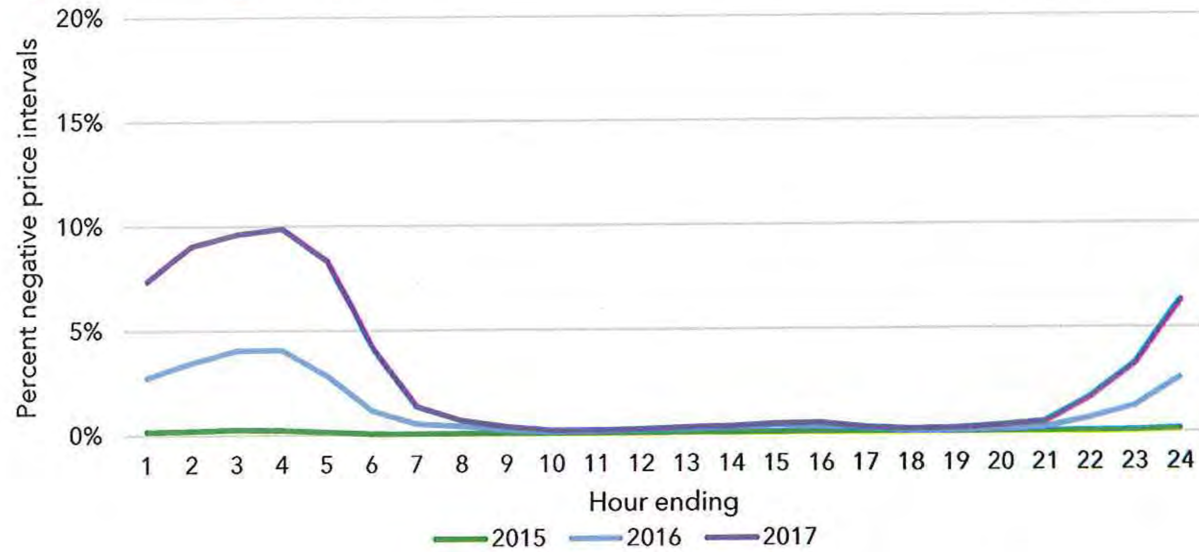
Figure 4-17 Negative price intervals, real time, by hour



This figure shows that the negative price intervals in 2017 during those overnight hours are at one and a half to two times the frequency of 2015 and 2016. During 2017 the first five hours and last two hours of the day experienced negative prices in over 10 percent of all intervals. The highest level in any hour during prior years was just 10 percent.

Negative price intervals in the day-ahead market (see Figure 4-18) follow the same pattern as the real-time market with most negative price intervals occurring in the overnight, low-load hours.

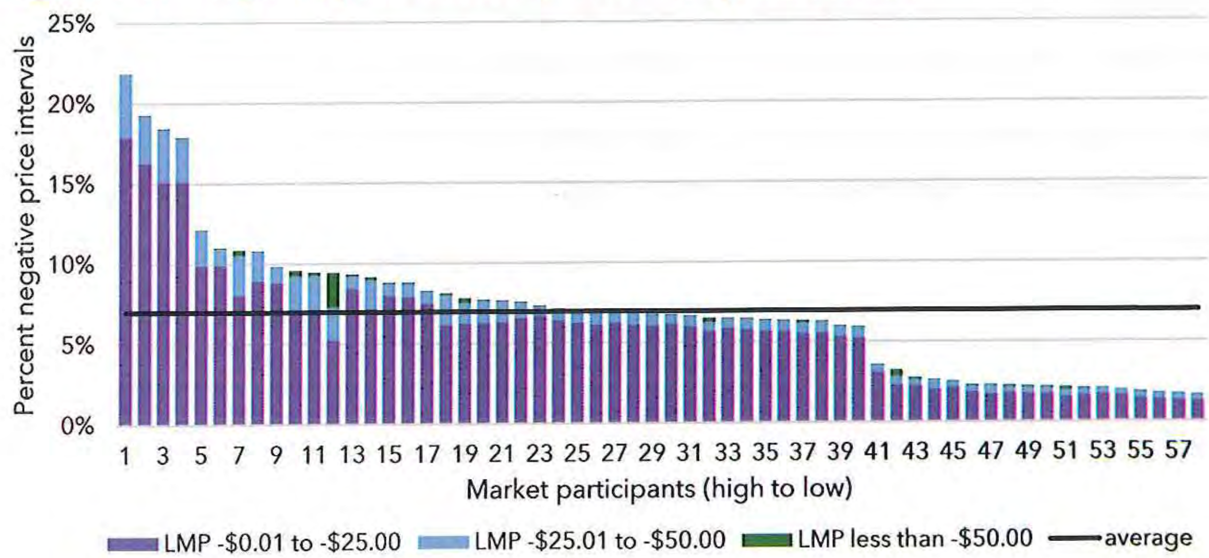
Figure 4-18 Negative price intervals, day-ahead, by hour



But again, this happens at a much lower frequency than in real time. Also of note, during the on-peak hours, less than 0.5 percent of intervals in the day-ahead market were negative. In 2017, the real-time market on average had nearly four percent of intervals with negative prices during the on-peak hours.

At the asset owner level (for those serving load), the distribution of negative price intervals during 2017 is clustered around the footprint average, as shown in Figure 4-19.

Figure 4-19 Negative price intervals, real time, by asset owner



However, four asset owners experienced negative prices in over 15 percent of all intervals. On the low end, 18 asset owners experienced negative prices in fewer than five percent of intervals.

The MMU is concerned with the marked increase in the frequency of negative price intervals. Negative prices may not be a problem in and of themselves, however, they do indicate an increase in surplus energy on the system. This may be exacerbated by the practice of self-committing after the day-ahead market. In the SPP market where there is an abundance of capacity and significant levels of renewable resources, negative prices can occur when renewable resources need to be backed down in order for traditional resources to meet their scheduled generation. Moreover, unit commitment differences, due to wind resources not being in the day-ahead market and then coming on-line for the real-time market, can create differences in the frequency of negative price intervals between the day-ahead and real-time markets. This disparity between the markets negatively impacts the efficient commitment of resources.

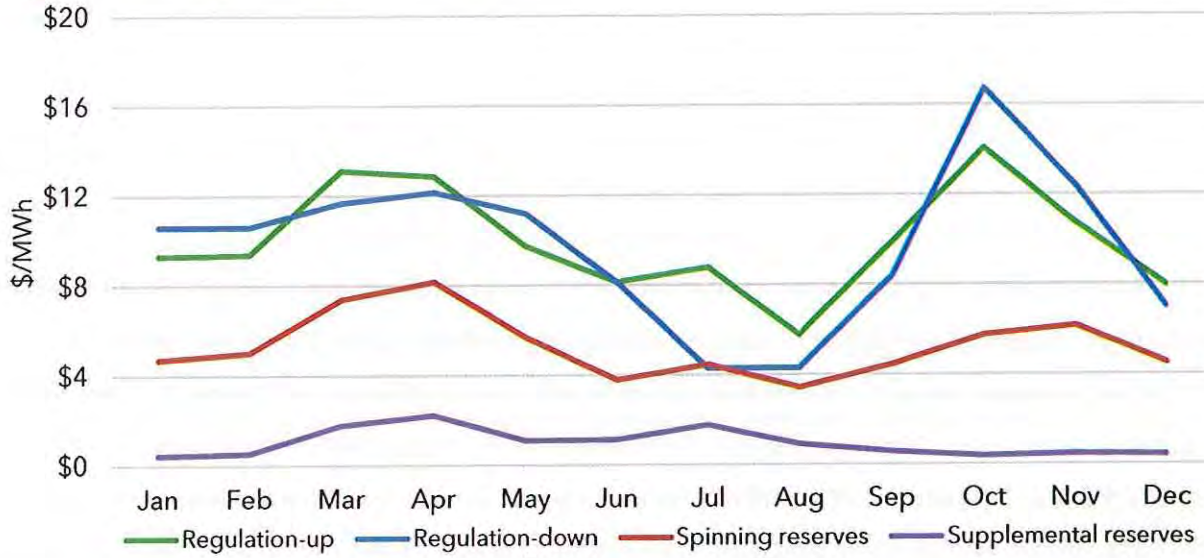
Thus, the growing frequency of negative prices indicates the need for changes in market rules to address self-committing of resources in the day-ahead market and the systematic absence of some forecasted variable energy resources in the day-ahead market to improve market efficiency. These issues are discussed further in Chapter 7.

4.1.7 OPERATING RESERVE MARKET PRICES

Operating reserve is made up of four products: (1) regulation-up, (2) regulation-down, (3) spinning reserve, and (4) supplemental reserve. The regulation products are used to ensure the amount of generation matches load on a subinterval basis. Generators respond to regulation instructions in seconds. Spinning and supplemental products are reserved for contingency situations and respond to instructions within ten minutes.

Average monthly real-time prices for operating reserve products are presented in Figure 4-20.

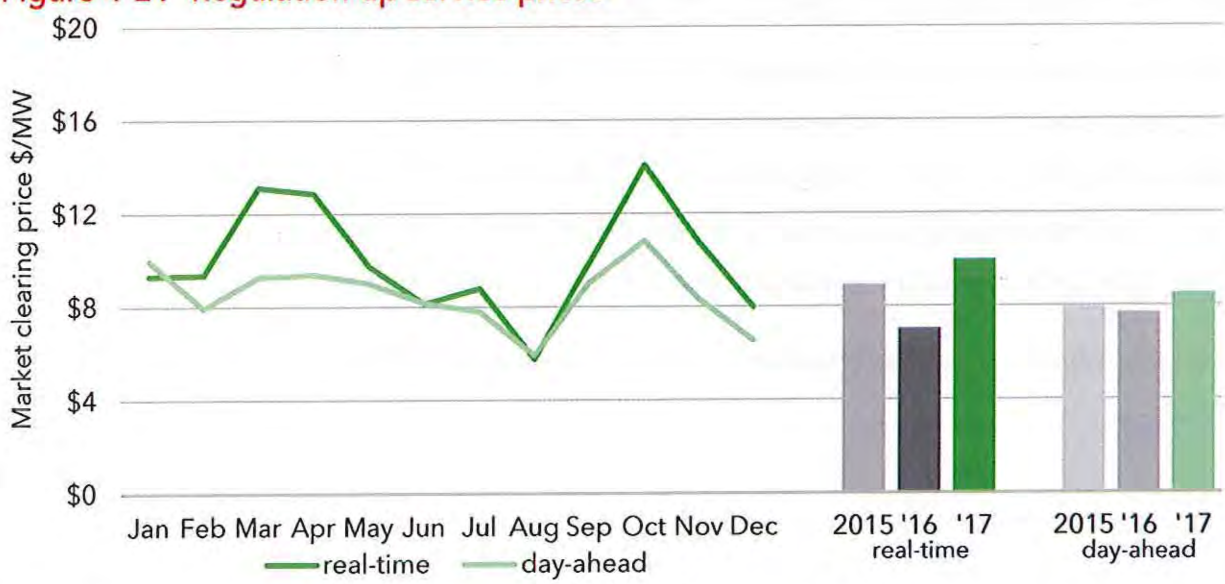
Figure 4-20 Operating reserve product prices, real time



Generally speaking, regulation-up and regulation-down have the highest market clearing prices. Supplemental reserves always have the lowest average prices of the operating reserve products, with prices averaging less than two dollars. Spinning reserve prices fall between regulation-up and supplemental reserve prices.

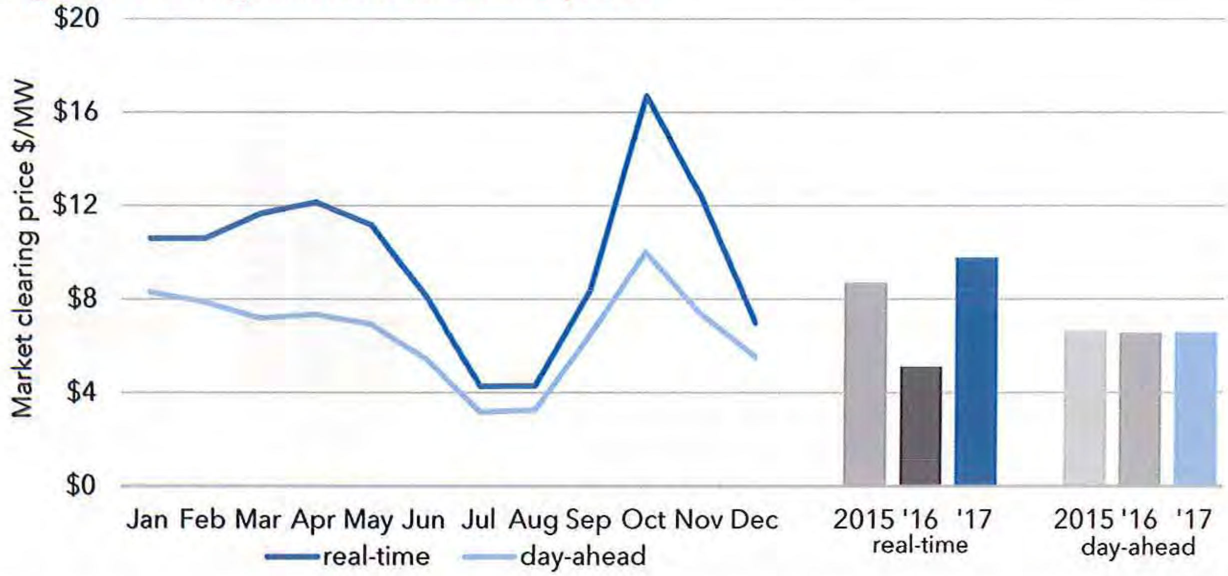
Day-ahead and real-time price patterns vary across the operating reserve products, see Figure 4-21 through Figure 4-24.

Figure 4-21 Regulation-up service prices



From 2016 to 2017, the average real-time market clearing price for regulation-up increased by 42 percent, from $7/MW to nearly $10/MW. Monthly prices for regulation-up were highest in the peak wind months during the spring and fall. The high prices during these periods can mostly be attributed to higher wind penetration levels during these periods.

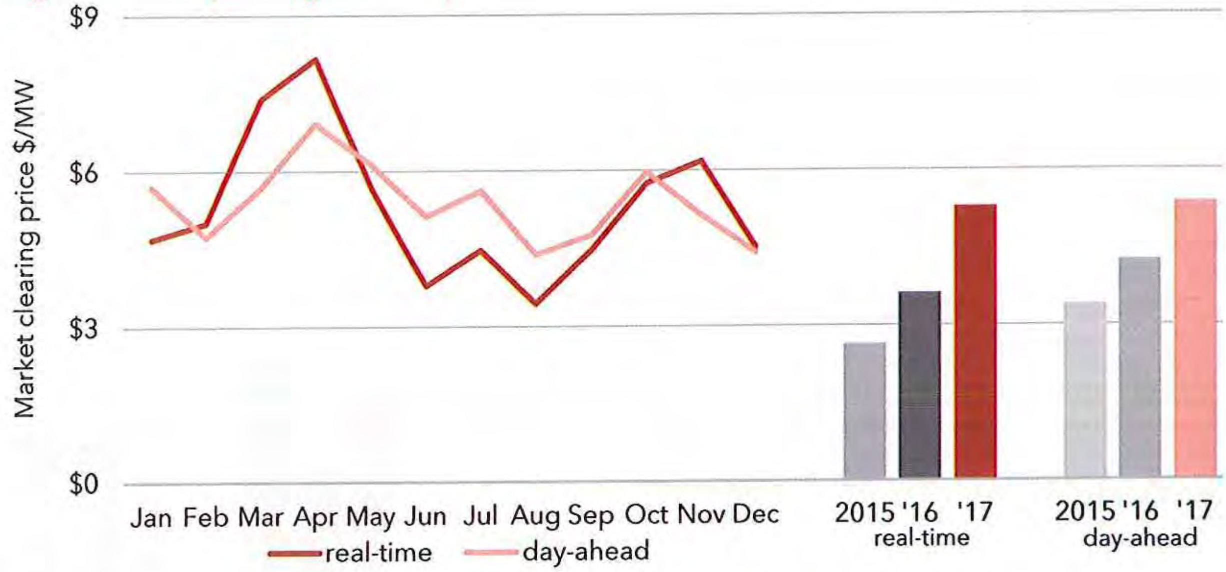
Figure 4-22 Regulation-down service prices



Regulation-down market clearing price in the real-time market nearly doubled from 2016 to 2017, going from just over $5/MW to nearly $10/MW. Day-ahead regulation-down market clearing prices have remained steady the past three years at around $6.50/MW.

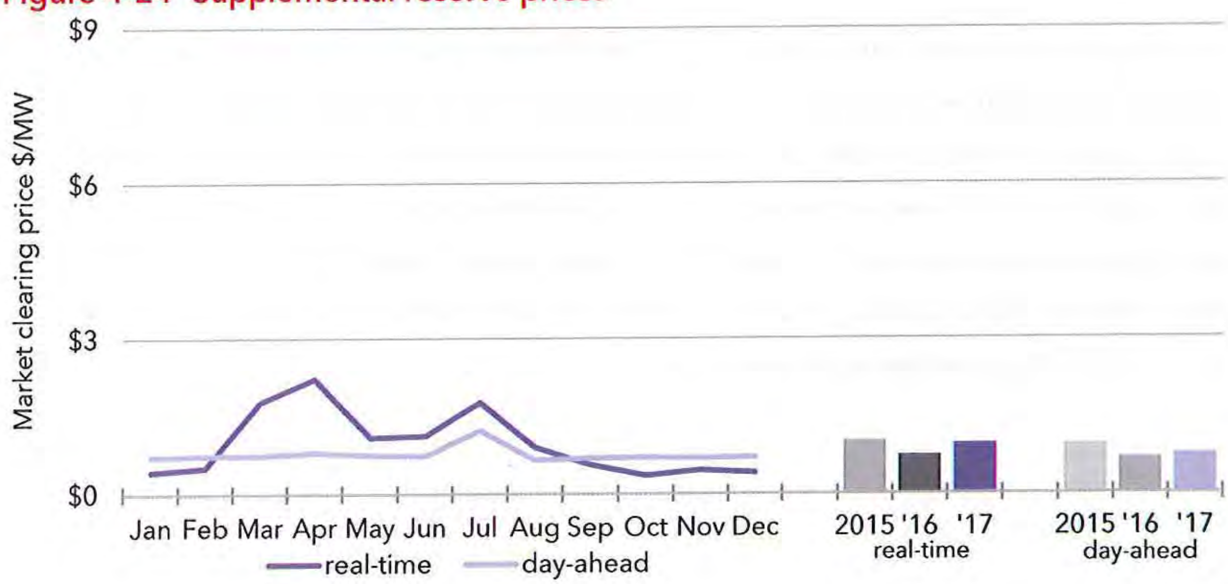
Monthly prices for regulation-down were at typical historical levels through September 2017. However, the real-time regulation-down market clearing price jumped from just over $8/MW in September to nearly $17/MW in October, and then $12/MW in November. The high real-time regulation-down market clearing prices can primarily be attributed to periods of high wind generation and low load. During these periods, many thermal units are operating at their economic minimums, which are lower than regulation minimums. Costs are higher to move these units up to the regulation range.

Figure 4-23 Spinning reserve prices



The market clearing price for spinning reserves continued to climb steadily on an annual basis in both the day-ahead and real-time markets. Even so, spinning reserve prices have been low overall, averaging about $5.25/MW in both markets annually in 2017, and peaking at just over $8/MW in the real-time market in September.

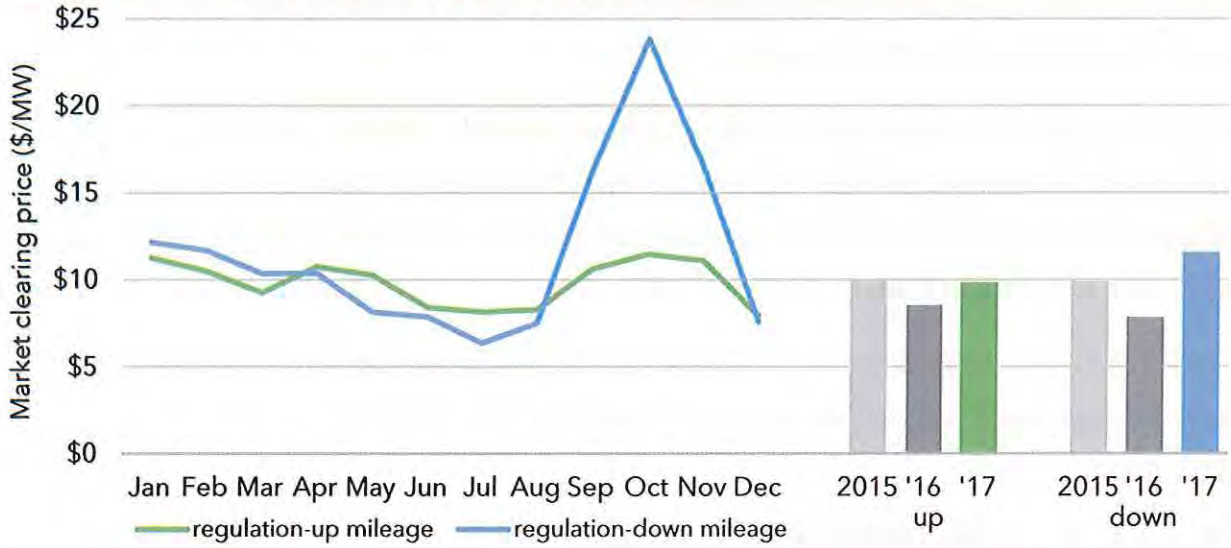
Figure 4-24 Supplemental reserve prices



Supplemental reserve market clearing prices remained low in both markets, with prices averaging less than $1/MW in 2017. On a monthly basis, monthly prices were highest in real time at just over $2/MW in April.

In March 2015, SPP introduced a new product paying regulating units for mileage costs incurred when moving from one set point instruction to another. These mileage payments are paid directly through the operating reserve prices shown for regulation-up and regulation-down, as shown in Figure 4-25. The market calculates a mileage factor for both products each month that represents the percentage a unit is expected to be deployed compared to what it cleared. If a unit is deployed more than the expected percentage, then the unit is entitled to reimbursement for the excess at the regulation mileage marginal clearing price. If the unit is deployed less, it must buy back its position.

Figure 4-25 Regulation mileage prices, real time



On an annual basis, average monthly regulation-up mileage prices for 2017 were almost identical to 2015, at around $10/MW. Levels in 2016 were slightly lower at around $8.50/MW. Average monthly regulation-down prices in 2017 were trending higher than previous year averages. However, the fall months of 2017 experienced very high regulation-down prices, peaking at an average for October of nearly $24/MW. The MMU is exploring the results during this period and will report on any findings in a subsequent forum or report.

4.1.8 MARKET SETTLEMENT RESULTS

The day-ahead market accounted for 98 percent of the energy consumed in the Integrated Marketplace. This is consistent with last year. Figure 4-26 shows that approximately 250 terawatt-hours of energy were purchased in the day-ahead market at load settlement locations, of which only five terawatt hours were in excess of the real-time consumption, requiring a sale back to the market.

Figure 4-26 Energy settlements, load

	Day-ahead purchases	Real-time purchases	Real-time Sales
Load (GWh)	-249,031	-5,332	5,058
Cash flow (millions)	-$ 6,053	-$ 139	$ 116

Just under five and a half terawatt hours of energy were purchased in the real-time market because the real-time consumption was higher than that of the day-ahead. The close relationship of day-ahead load consumption to real-time load consumption demonstrates signs of an efficient day-ahead market.

Negative gigawatt hours denote withdrawals from the grid. Negative cash flows denote charges to load-serving entities. Positive gigawatt hours represent sales of day-ahead gigawatt hours back to the real-time market and negative cash flows represent payments to load owners for those sales.

Day-ahead generation accounted for 89 percent of generation settled in the market, a three percent decrease from last year. Figure 4-27 presents the settlement numbers for the SPP generators.

Figure 4-27 Energy settlements, generation

	Day-ahead sales	Real-time sales	Real-time purchases
Generation (GWh)	254,433	33,103	-27,626
Cash flow (millions)	$ 5,560	$ 478	-$ 563

Eleven percent of the energy cleared in the day-ahead market was settled by purchasing energy in the real-time market rather than generating the energy, which was roughly the same as experienced in 2015 and 2016.

Positive gigawatt hours denote injections into the grid. Positive cash flows denote payments to generators. Negative gigawatt hours represent repurchases in the real-time market and negative cash flows represent charges to generators for those repurchases.

SPP plays the role of the customer in the operating reserve market. At hour ending 8:00 AM on the day before the operating day, SPP posts the forecasted amount of each operating reserve product that is to be procured. This data sets the demand for the products for the day-ahead market. SPP can change the demand levels after the clearing of the day-ahead market. Even though the demand is essentially the same between the day-ahead market and the real-time market, there is considerable activity with respect to the operating reserve products in the real-time market. Figure 4-28 presents the settlements data for operating reserves.

Figure 4-28 Operating reserve product settlements

Settlements (GWh)*	Day-ahead sales	Real-time sales	Real-time purchases
Regulation-up	2,785	936	-938
Regulation-down	2,791	1,040	-1,041
Spinning reserves	6,599	1,948	-1,946
Supplemental reserves	6,601	2,488	- 2,478

Positive numbers represent the cleared gigawatt hours for ancillary services. Negative numbers represent the repurchase of day-ahead cleared ancillary service in the real-time market.

A large percentage of day-ahead sales (34 percent) are settled in the real-time market by repurchasing the operating reserve product rather than supplying the service in the real-time market. This is in contrast to 89 percent of energy generation settled at the day-ahead prices. This trend is down three percent from last year and eight percent from the 40 percent that occurred in the first 12 months of the market.

Sixty-six percent of the 2017 real-time regulation-up service was settled at day-ahead prices, up one percent from 65 percent in the previous year. The corresponding percentages for regulation-down service, spinning reserves, and supplemental reserves are 63 percent, 71 percent, and 62 percent respectively. These results were up slightly from the respective numbers in 2016 of 58 percent, 70 percent, and 61 percent. This essentially means that operating reserve products are being moved around to different resources in about the same volumes as last year, with the exception of regulation-down. It had a five percent increase in real-time volume when compared to day-ahead volume. This is likely a result of differences in generation between the day-ahead and real time including differences in wind generation as well as virtual bids and offers.[60]

4.2 SCARCITY PRICING

The Integrated Marketplace uses scarcity pricing demand curves that administratively set prices during periods of shortage. An efficient electricity price reflects the cost of the marginal action required to meet the market demand. Generally, generators are the marginal price setting resource. However, during shortage pricing events, the marginal megawatt comes from reducing the amount of operating reserves. The scarcity pricing demand curves reflect the administratively determined cost of the marginal action during operating reserve shortages.

FERC Order No. 825 was released in June 2016. The order stated that: "[W]e require each RTO/ISO to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval." At the time of the order, SPP did not price ramp related shortages because those events were considered transient in nature.

Revision request 175 "Ramp Shortage Compliance" was developed to bring SPP in compliance with FERC Order No. 825 and was implemented on May 11, 2017. Specifically, the revision request removed the violation relaxation limits for resource capacity constraints, resource ramp constraints, and global power constraints. It also established an energy demand price of $5,000 and removed the relaxing of each products' ramp requirements, which allowed ramp shortages to be effectively priced.

SPP market participants anticipated that pricing ramp scarcity events would cause more real-time price spikes, increasing real-time price volatility. Revision request 198 was introduced to minimize the impacts of these increased scarcity events and was implemented on August 11, 2017. The revision request put variable price demand curves in place of the fixed price demand curves. These variable price demand curves buffer the impacts of scarcity pricing.

[60] Section 4.1.5 details the differences in generation outputs between the day-ahead and real-time markets.

Prior to revision request 198, each products' scarcity demand curves used one scarcity price. Now regulation-up, regulation-down, and contingency reserves have multiple price points depending on how short the cleared operating reserve was of the requirement. For example, regulation-up and regulation-down had one scarcity price of $600/MW prior to August implementation. This meant that being short just one megawatt of regulation capacity would cause a $600/MW price for that product. Since August 11, regulation-up and regulation-down demand curves now have six monotonically increasing price points. Each month SPP runs an analysis on the per megawatt cost to commit a quick-start resource in the prior month. This cost is used to set the regulation scarcity demand curve prices. Regulation-down works exactly the same as regulation-up, except it will have a separate clearing requirement.

Figure 4-29 is an example of how the regulation-up pricing points look after implementation of revision request 198, assuming the historical cost per megawatt to deploy a quick-start unit was $468/MWh.

Figure 4-29 Regulation-up variable demand curve pricing example

Regulation-up demand curve break points	Percent of average quick-start's cost to start for prior month (assuming cost of $468)	Break point shadow price
Amount cleared is:		
Greater than 80 percent, but less than requirement	0.25	$ 117
Between 60 and 80 percent	0.50	234
Between 40 and 60 percent	0.75	351
Between 20 and 40 percent	1.00	468
Above 0, but less than 20 percent	1.25	585
None	capped at $600	600

Figure 4-30 is an example of how the operating reserve demand curves work after revision request 198.

Figure 4-30 Contingency reserve demand curve pricing example

Contingency reserve demand curve break points	Contingency reserve scarcity factor	Break point shadow price
Amount cleared is:		
Less than or equal to 25 percent of second largest projected resources maximum normal operating capacity	0.25	$ 275
Between 25 and 50 percent of second largest projected resources maximum normal operating capacity	0.50	550
Greater than 50 percent of second largest projected resources maximum normal operating capacity	1.00	1,100

FERC stated that the removal of the violation relaxation limits for resource capacity constraints, resource ramp constraints, and global power constraints was in excess of what was required for compliance with FERC Order No. 825 and informed SPP that the implementation was further than needed. To comply, SPP brought forward revision request 265 to add back those items and remove the $5,000 scarcity price for energy. SPP implemented the changes consistent with this revision request on December 5.

As an outcome of SPP pricing the ramp shortages, the MMU has challenges discerning capacity shortages from ramp shortages. This has to do with how the clearing engine solves for scarcity events. The clearing engine does two runs, one for capacity scarcity, and another for ramp scarcity. The results of these two runs are combined for the total scarcity events. The MMU strongly suggests that SPP capture the decisions of both runs so that the reason for the scarcity will be transparent.

Figure 4-31 displays the number of ramp and scarcity shortage intervals by month prior to the scarcity changes in May. The figure also illustrates the average marginal energy component during those intervals. Figure 4-32 displays the number of ramp and scarcity shortages intervals after the May implementation.

Figure 4-31 Scarcity intervals and marginal energy cost, before changes

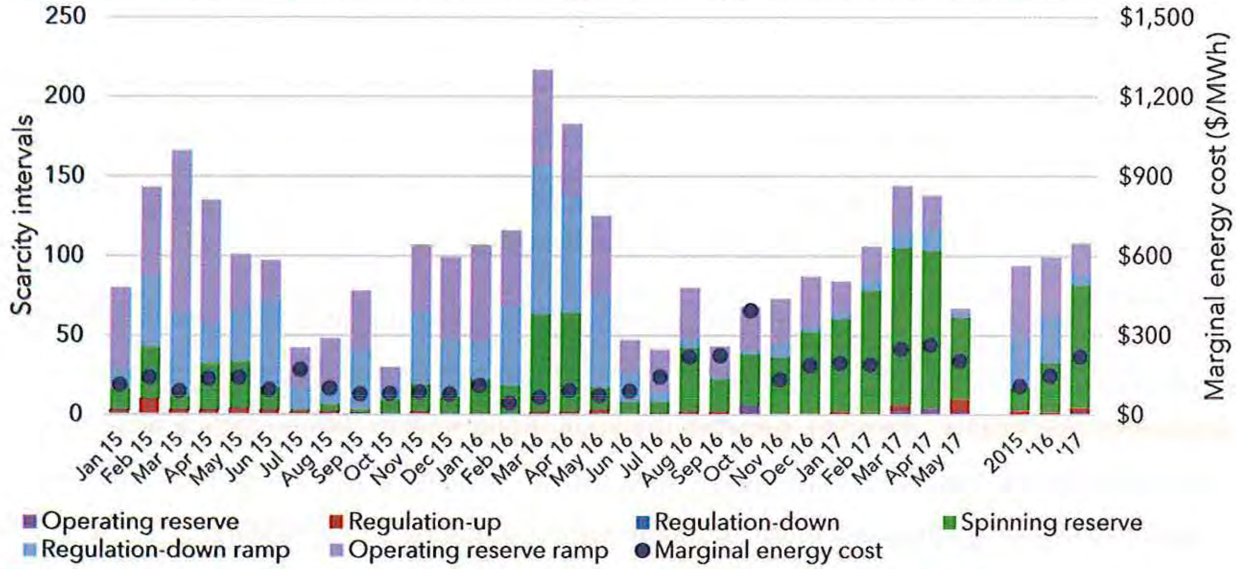
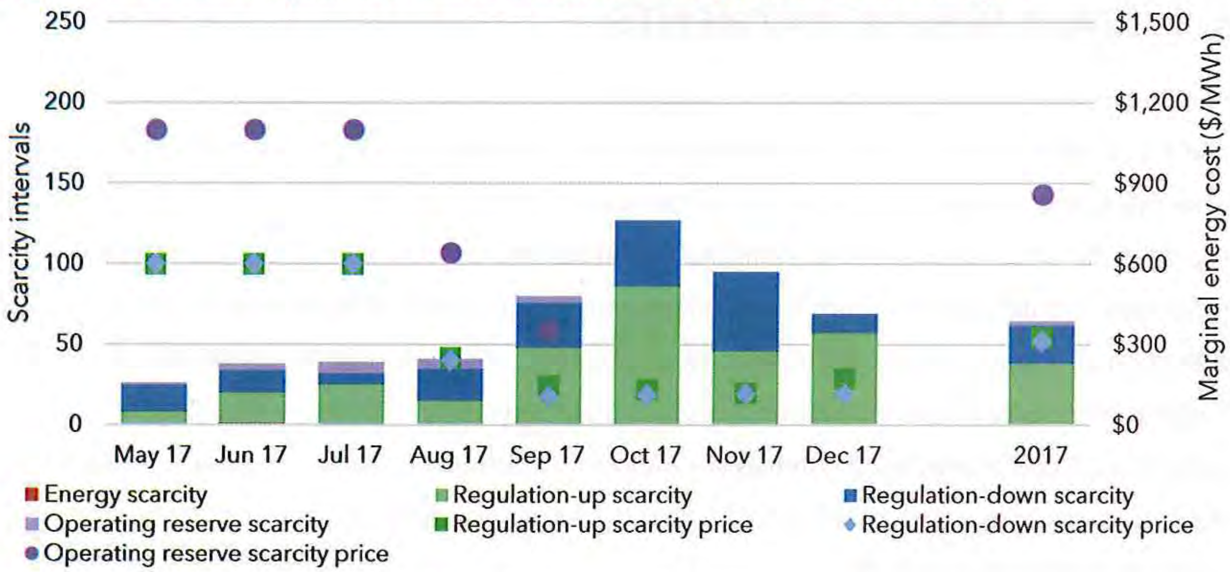


Figure 4-32 Scarcity intervals and marginal energy cost, after changes



Between January 1 and May 11, 2017 there were nine intervals with regulation-up scarcity, no intervals with regulation-down scarcity, 384 intervals of spin scarcity, and 16 intervals with operating reserve scarcity. In addition, there were no regulation-up ramp scarcity events, 37 regulation-down ramp scarcity events, 374 spin ramp scarcity events, and 95 operating reserve ramp scarcity events. However, none of the ramp scarcity events were being priced during this period.

Starting on May 11, there were 304 regulation-up scarcity events, 188 regulation-down scarcity events, and 22 operating reserve events. Figure 4.22 shows the average marginal clearing price of each product during the scarcity intervals. Prior to revision request 198, which was implemented on August 11, the regulation products had one offer price of $600/MW, and the operating reserves had one price of $1,100/MW. After revision request 198, the average price of scarcity for regulation-up was $187/MW, regulation-down was $113/MW, and operating scarcity was $374/MW. This shows that the variable offer curves were successful in reducing the effects of the scarcity events.

There was one energy scarcity event priced at $5,000 in 2017 on June 7. This was because of a system ramp violation caused by the loss of a 632 MW unit during a period when wind generation was falling. However, because the $5,000/MW energy demand price was removed in December, consistent with revision request 265, no subsequent values will occur at this level unless changes are made to increase the value back to $5,000/MW.

4.3 MAKE-WHOLE PAYMENTS

The Integrated Marketplace provides make-whole payments (MWPs) to generators to ensure that the market provides sufficient revenue to cover the cleared offers providing energy and operating reserves for a period in which the resource was committed. To preserve the incentive for a resource to meet its market commitment and dispatch instruction, market payments should cover the sum of the incremental energy cost, start-up cost, no-load cost, transition cost, and cost of operating reserve products. Any revenue beyond those costs supports recovery of fixed costs and provides a profit margin. The make-whole payment provides additional market payments in cases where revenue is below a resource's offers to make the resource whole to its offers of operating reserve products, incremental energy, start-up, transition, and no-load.

For resources that are not combined-cycle, settlements calculations separately evaluate: (1) day-ahead market commitments based on day-ahead market prices, cleared offers and dispatch; and (2) reliability unit commitments based on real-time market prices, cleared offers, and dispatch. Combined-cycle resources can be cleared in both the day-ahead and real-time markets at the same time. This is unique to combined-cycles. As a result, settlements must evaluate the revenues and cost of both real-time and day-ahead commitments when calculating real-time make-whole payments for combined-cycles.

For 2017, day-ahead market and reliability unit commitment make-whole payments totaled approximately $68 million, down from $71 million last year. Make-whole payments averaged about $0.26/MWh for 2017. SPP's make-whole payments are comparable to results in other RTO/ISO markets, which varied from $0.22/MWh to $0.57/MWh in 2016.[61]

Figure 4-33 shows monthly and annual day-ahead make-whole payment totals by technology type. Figure 4-34 shows the same make-whole payment information for reliability unit commitment.

Figure 4-33 Make-whole payments by fuel type, day-ahead

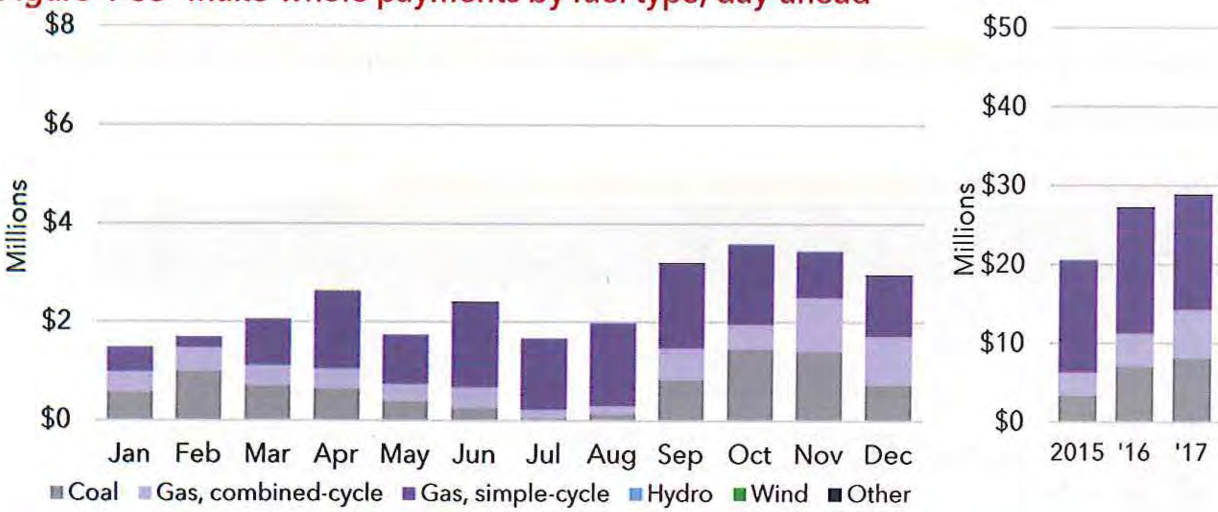
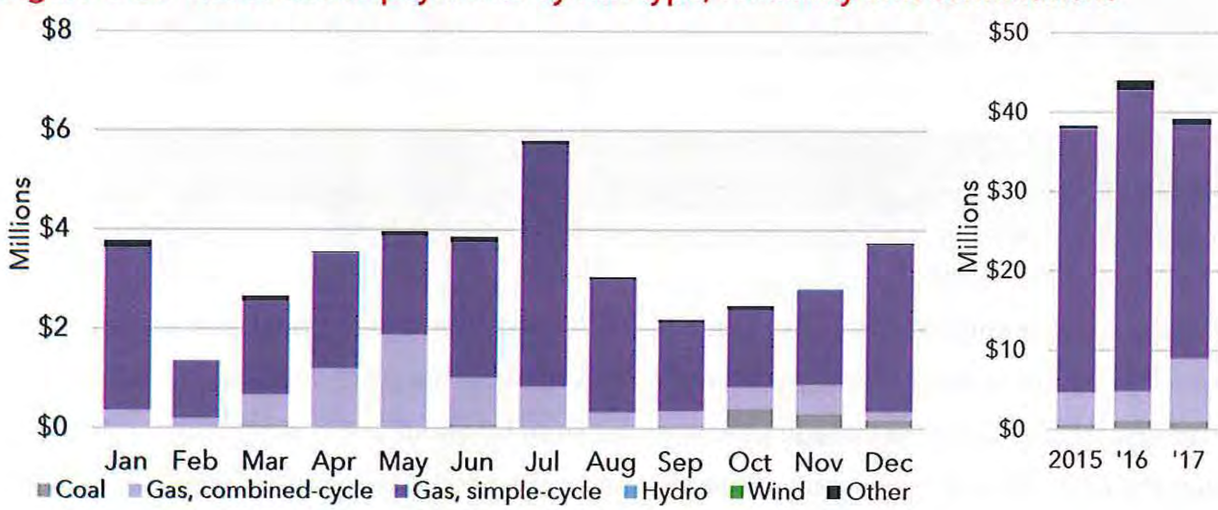


Figure 4-34 Make-whole payments by fuel type, reliability unit commitment



[61] ISO NE State of Market Report https://www.potomaceconomics.com/wp-content/uploads/2017/07/ISO-NE-2016-SOM-Report_Full-Report_Final.pdf , MISO Annual state of Market report http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec4.pdf , PJM website www.pjm.com

Day-ahead make-whole payments constituted just over 42 percent of the total make-whole payments in 2017. Gas-fired resources represent about 85 percent of all make-whole payments, with 65 percent of all make-whole payments to simple-cycle gas resources through reliability unit commitment make-whole payments.

Make-whole payments occur for several reasons, which include some of the following: local reliability commitments, uncaptured congestion in the day-ahead market, inflexibility of resources to move in economic ranges between on-peak and off-peak hours, and excessive transmission congestion not being solved by the market.

Figure 4-35 shows the share of each cause of make-whole payments in the real-time and day-ahead markets.

Figure 4-35 Make-whole payments, commitment reasons

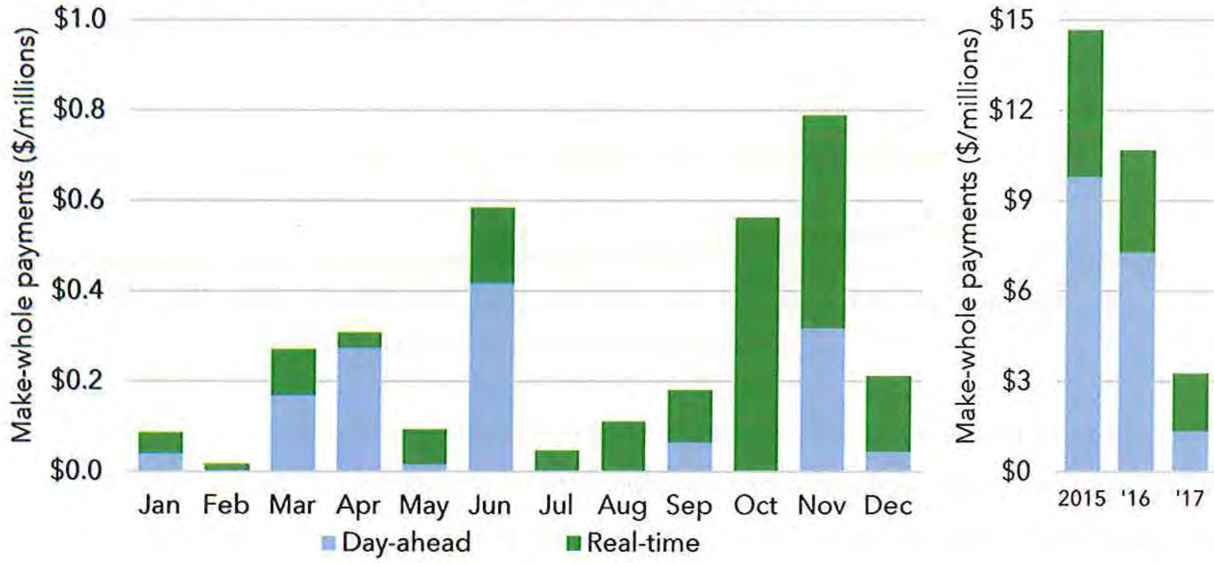
Real-time commitment reason	2015	2016	2017
Intra-day RUC	21.6%	24.4%	35.7%
Manual, SPP transmission	8.9%	23.2%	31.6%
Day-ahead RUC	33.8%	20.1%	7.5%
Short-term RUC	0.0%	12.9%	6.1%
Manual, intra-day RUC	17.2%	8.4%	6.1%
Manual, voltage	13.5%	8.0%	6.4%
Manual, SPP capacity	4.3%	2.6%	4.5%
Manual, day-ahead RUC	0.1%	0.3%	1.2%
Manual, off supplemental	0.0%	0.1%	0.0%
Other	0.6%	0.0%	0.8%

Day-ahead commitment reason	2015	2016	2017
Day-ahead market	53.4%	73.2%	93.7%
Manual, voltage support	46.6%	26.8%	6.3%

Voltage support commitments decreased in 2017 when compared to prior years, declining from 47 percent of make-whole payments in 2015 to about six percent in the day-ahead market in 2017. Real-time voltage payments declined by about seven percentage points over the same period. As a result of this change, make-whole payments for intra-day reliability unit commitment and manual-transmission commitments increased in the real-time market.

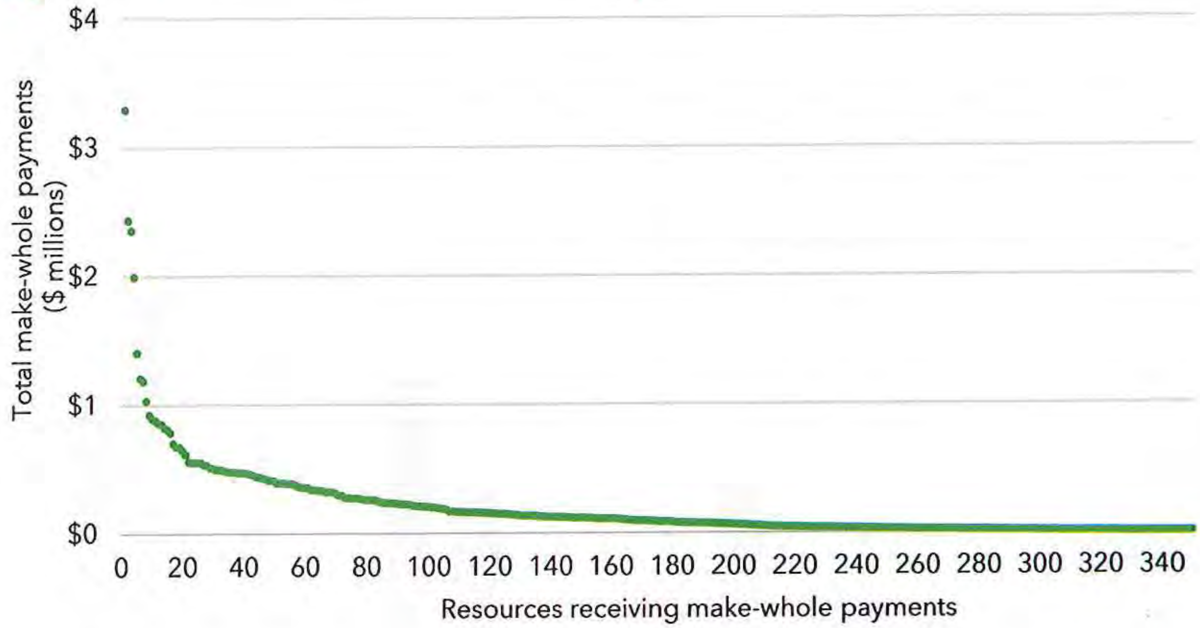
Make-whole payments associated with voltage support commitments do not follow the same uplift process outlined previously in this section. Instead, the cost of these make-whole payments are distributed to the settlement areas that benefited from the commitment by way of a load ratio share. Figure 4-36 illustrates the level of make-whole payments associated with voltage support commitments.

Figure 4-36 Make-whole payments for voltage support



Most SPP resources received modest total annual make-whole payments as highlighted in Figure 4-37.

Figure 4-37 Concentration of make-whole payments by resource



The majority of resources in SPP received less than $200,000 in make-whole payments in 2017. Eight resources received over $1 million, with three of those resources receiving over $2 million. Both of these numbers are twice the level as last year. Five of the top eight resources were run extensively for voltage support, with over 90 percent of the top units' make-whole payments attributed to voltage support commitments. One resource received $3.2 million dollars in make-whole payments, and was mostly committed for reliability reasons.

Figure 4-38 reveals some concentration in the market participants that received the highest levels of make-whole payments. The overall numbers have not changed significantly over the past few years.

Figure 4-38 Market participants receiving make-whole payments

	2015			2016			2017		
	> $1 million	> $5 million	> $10 million	> $1 million	> $5 million	> $10 million	> $1 million	> $5 million	> $10 million
Market participants receiving make-whole payments	12	5	0	12	4	2	12	5	1
% of make-whole payments by category	93%	65%	0%	92%	61%	38%	90%	61%	18%

In 2017, there were 12 market participants that each received annual make-whole payments in amounts greater than $1 million. These 12 market participants accounted for 90 percent of the total make- whole payments paid out in 2017. Those same 12 participants also received over $1 million each in 2016 and 11 of those participants received over $1 million in 2015. There was only one participant in 2015 that was different from 2017 at this level. In 2017, there were five participants that received over $5 million each in make-whole payments and out of that one received $10 million. The participant with $10 million in total make-whole payments accounted for 18 percent of all make-whole payments paid out in 2017.

4.3.1 MAKE-WHOLE PAYMENT ALLOCATION

The allocation of both day-ahead and real-time make-whole payments has important consequences to the market. In principle, for market efficiency purposes uplift cost allocation should be directed to those members that contributed to the need for the make-whole payments (i.e., cost causation).

For the day-ahead market, make-whole payment costs are distributed to both physical and virtual withdrawals on a per-MWh rate. The per-MWh rate is derived by dividing the sum of all day-ahead make-whole payments for an operating day by the sum of all cleared day-ahead market load megawatts, export megawatts, and virtual bids for the operating day. The average per-MWh rate for withdrawing locations in the day-ahead market was just under $0.11/MWh in 2017. This is similar to the 2016 average and slightly higher than the $0.09/MWh average in 2015.

For the real-time market, make-whole payment costs are distributed through a per-MWh rate that is assigned to all megawatt-hours of deviation in the real-time market. The average real-time distribution rate was $0.90/MWh for 2017, down $0.24/MWh from the $1.14/MWh average in 2016. There are eight categories of deviation and each category receives an equal amount per megawatt when the cost of make-whole payments is applied. This can be seen in the settlement location deviation charge, show in Figure 4-39.

Figure 4-39 Make-whole payments by market uplift allocation, real time

Uplift type	Deviation MWs (thousands)	Uplift charge (thousands)	Share of MWP charges	Cost per MW of deviation
Settlement location deviation	35,149	$ 30,902	78.9%	$ 0.88
Outage deviation	4,402	$ 4,066	10.4%	$ 0.92
Status deviation	1,436	$ 1,266	3.2%	$ 0.88
Maximum limit deviation	1,200	$ 1,205	3.1%	$ 1.00
Reliability unit commitment self-commit deviation	629	$ 592	1.5%	$ 0.94
Uninstructed resource deviation	659	$ 584	1.5%	$ 0.89
Minimum limit deviation	283	$ 233	0.6%	$ 0.00
Reliability unit commitment deviation	245	$ 309	0.8%	$ 0.00

Even though each category of deviation is applied the same rate for deviation, approximately 79 percent of the real-time make-whole payment costs were paid by entities withdrawing (physical or virtual) more megawatts in the real-time market than the day-ahead market.

Transactions susceptible to this charge are virtual offer megawatts, real-time load megawatts in excess of the day-cleared megawatts for a unit, exporting megawatts in real time in excess of the export megawatts cleared in the day-ahead market, and units pulling substation power in excess of any megawatts produced by the unit.

4.3.2 REGULATION MILEAGE MAKE-WHOLE PAYMENTS

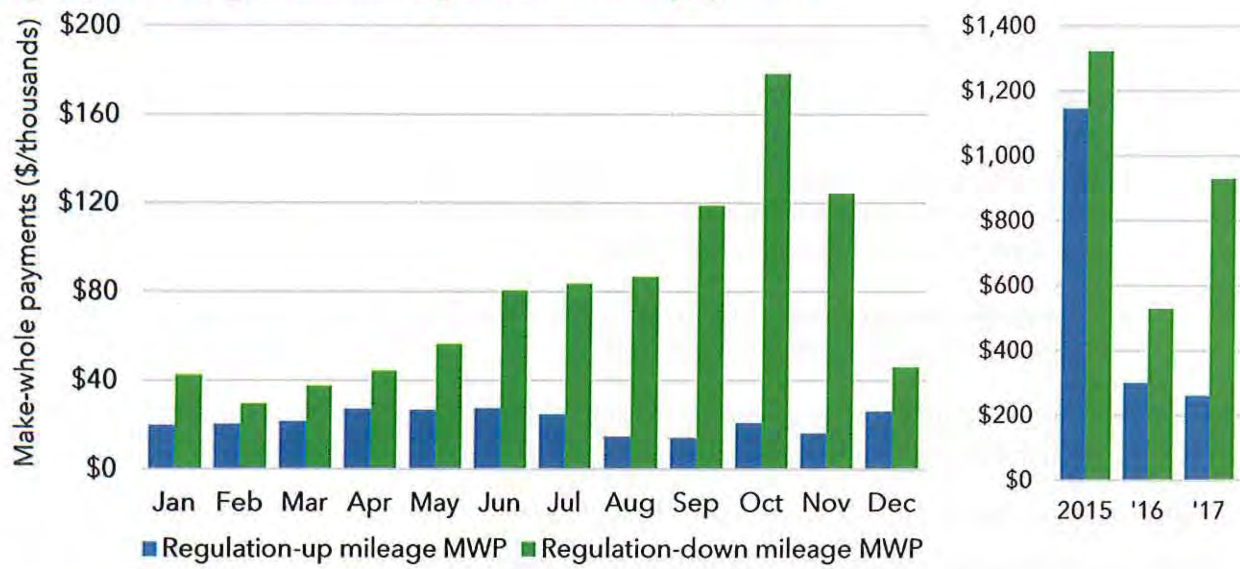
In March 2015, SPP introduced regulation compensation changes for units deployed for regulation-up and regulation-down. One component of the regulation compensation charges is regulation-up and regulation-down mileage make-whole payments for units that are charged for unused regulation-up or regulation-down mileage at a rate that is in excess of the regulation-up or regulation-down mileage offer.

SPP calculates mileage factors monthly for both regulation-up and regulation-down. These mileage factors are ratios of historical averages of the percentage of each regulation product deployed to the regulation product cleared in the prior month. The regulation-up mileage factor and regulation-down mileage factors averaged 18 percent and 24 percent, respectively, for 2017. While the regulation-up mileage factor stayed the same from 2016, the regulation-down mileage factor increased four percent.

The mileage factor is a key component in the computation of mileage make-whole payments. When the mileage factor is greater than the percentage of deployed regulating megawatts to cleared regulating megawatts for each product, the resource must buy back the non-deployed megawatts at the mileage marginal clearing price for the respective product. If the mileage marginal clearing price used for the buyback is greater than the unit's cost for the product a make-whole payment may be granted.

Figure 4-40, below, illustrates the mileage make-whole payments for 2017 and the prior two years.[62]

Figure 4-40 Regulation mileage make-whole payments



The large increase in regulation-down make-whole payments for the second half of 2017 can be directly attributed to a the mileage clearing prices for regulation-down being nearly

[62] There were a large number of mileage make-whole payments paid out in 2015. This is because the mileage process was rolled out in March of that year and there was not historical data to forecast mileage factors, so the factors were set to 100 percent in the first month of the rollout. This resulted in buyback that was eligible for make-whole payments.

$50/MW for some intervals in the latter half of 2017. The MMU continues to review these results and its implications on market design. We plan to report on our conclusions when our findings are complete.

4.3.3 POTENTIAL FOR MANIPULATION OF MAKE-WHOLE PAYMENTS

In the 2014 Annual State of the Market Report, the MMU highlighted four specific vulnerabilities that market participants could potentially manipulate in SPP's make-whole payment provisions. Three of the four vulnerabilities were directly associated with the FERC order regarding the make-whole payments and related bidding strategies of JP Morgan Ventures Energy Corp.[63] Shortly before the launch of the Integrated Marketplace, SPP and the MMU noted the following exposures in SPP's market design:

1) make-whole payments for generators committed across the midnight hour,
2) make-whole payments for regulation deployment, and
3) make-whole payments for out-of-merit energy.

In 2014, one of the MMU's recommendations covered the following with regard to the manipulations of make-whole payment provisions:

1) evaluate solutions adopted by other RTOs to reduce exposure to market manipulation opportunities in make-whole payment provisions for resources committed across the midnight hour,
2) disqualify resources with fixed regulation offers from receiving the regulation deployment adjustment charge, and
3) utilize automatic mitigation provisions for local reliability commitments for local reliability out-of-merit energy events.

In each case, a market participant has the ability to position its resource to receive a make-whole payment without economic evaluation of its offers by the market. While no resolution has been completed for these items at this time, there are solutions at different stages of development for each of these items.

[63] See 144 FERC 61,068.

A revision request was brought forward regarding multi-day minimum run times to ensure that units with long minimum run times could not manipulate their make-whole payments by inflating their offers on days subsequent to the initial commitment.[64] Though the Market Working Group rejected the revision request in early 2017, the MMU successfully appealed the rejection to the Market Operations and Policy Committee and the revision request was remanded back to the Market Working Group for further review. The MMU continues work with the Market Working Group to address this issue. A proposed solution is under development and is currently targeted for SPP board approval in July.

Two revision requests were brought forward to address the issue concerning regulation adjustments. One adds an assessment of economics when deploying units for regulation and the other caps the offers used for the adjustment. The first has been implemented while the latter was approved by FERC in early April 2018. The MMU feels that these two revision requests will adequately close the gaming opportunities present in the regulation adjustment.[65]

Because exposures to all three vulnerabilities are still present, the MMU continues to monitor the market for all three of these gaps. This is necessary to prevent exploitation of the third gap concerning out-of-merit energy make-whole payments. Because of the infrequency of these events, the MMU continues to monitor the gap, as the cost of changes may outweigh the benefits of a market design change at this time.

4.3.4 JOINTLY-OWNED UNIT MAKE-WHOLE PAYMENTS

Another make-whole payment concern existed related to jointly-owned resources and the combined resource option. At the time the MMU made their original recommendation, the market committed jointly-owned units as one unit, dispatched each separate owner on a percentage of ownership, and paid make-whole payments for energy based on the individual owners' energy offers. This allowed a shareowner to benefit from a higher energy offer than its co-owners through high minimum energy costs in the make-whole payment.

In August 2017, SPP implemented changes based on two revision requests to eliminate the gaming opportunities present in the original design. The new design eliminates the potential

[64] RR 221 (2014 ASOM MWP MMU Recommendation [3-Day Minimum Run Time])
[65] The revision requests were 242 and 243.

gaming opportunity by taking all owners' pricing points of a combined resource option for jointly-owned resources and aggregates those price points into a single energy offer curve for the unit. This revision request also enforced all shares under a combined resource option to have a minimum capacity limit of zero megawatts when being assessed for dispatch. Start-up and no-load costs were still reimbursed on the same percentage of ownership method used prior to the changes.

With the new method, individual shares only received a dispatch instruction greater than zero megawatts based on the new aggregated energy offer curve, which eliminated the original gaming opportunity. Figure 4-41, below, illustrates how a hypothetical energy offer curve looked once aggregated.

Figure 4-41 Aggregated energy offer curve example

If this unit were to clear economically, asset owner A would have been dispatched for the first 10 megawatts. Then asset owner B would be dispatched from 10 MW to 20 MW, as they were the most economical for those segments. This process would have been repeated until the desired quantity was reached.

While the change eliminated the gaming opportunity outlined in the 2014 annual state of the market report, the design introduced new issues. These issues include the following:

1) Allocating self-committed jointly-owned unit costs during uneconomic periods

One of the biggest issues brought forward by participants with jointly-owned units was how the new design allocated costs when these resources were self-committed and uneconomic. For example, if the resource is self-committed, there are times when the price of energy may be negative for several hours during that commitment. During these uneconomic periods the lowest cost parts of the jointly-owned unit will be cleared to meet the unit's minimum physical capacity operating limit. Using the energy offer curve in Figure 4-41, and assuming a minimum physical capacity operating limit of 20 MW, only asset owner A and B will be dispatched to meet the 20 MW requirement. Because the unit is self-committed, no members are eligible for cost reimbursement. However, asset owner A and asset owner B will have to cover the costs of running during periods with negative prices, whereas asset owner C will not have to cover the costs. Under the old method, the cost of negative prices would have been distributed by percentage of ownership, so each asset owner would have to cover this cost.

2) Gap created in real-time make-whole payments for jointly-operated units

Units committed after the day-ahead market are eligible for real-time make-whole payments. Real-time make-whole payments allow eligible units to recover cost on their energy if prices do not cover the cost to produce the energy. The energy cost assessed up to the unit's minimum are the costs submitted at the time of the commitment. The energy cost above the unit's minimum are the cost that are submitted at the time of dispatch. These energy offers at the time of dispatch are known as "as-dispatch" offers. The as-dispatch offers may be updated 30 minutes prior to each operating hour. A jointly-owned unit cleared in any process after the day-ahead market–such as the reliability unit commitment process–can inflate their offers at the time of dispatch and be made whole to that inflated offer, even though the jointly-owned unit may be running at its physical minimum limit. This is because each jointly-owned unit owners' minimum operating limits are considered zero megawatts for settlement even though the unit is only running above zero megawatts because of the physical minimum limits of the unit. Thus, if an asset owner knows that a resource is committed to minimum, they have the ability to increase their energy offers–which do not account for minimum load levels–to increase their make-whole payments.

3) Real-time make-whole payment distributions not accurately applied

The real-time make-whole distribution allocates the cost of real-time make-whole payments to deviating megawatts. One category of deviating megawatts are units that self-commit in the real-time market and are dispatched to their minimum limit. The difference in the megawatts between the minimum limit of the resource and the desired energy level are allocated costs for real-time make-whole payments. Because each co-owners have zero minimum capacity limits in settlements, they are not allocated these costs.

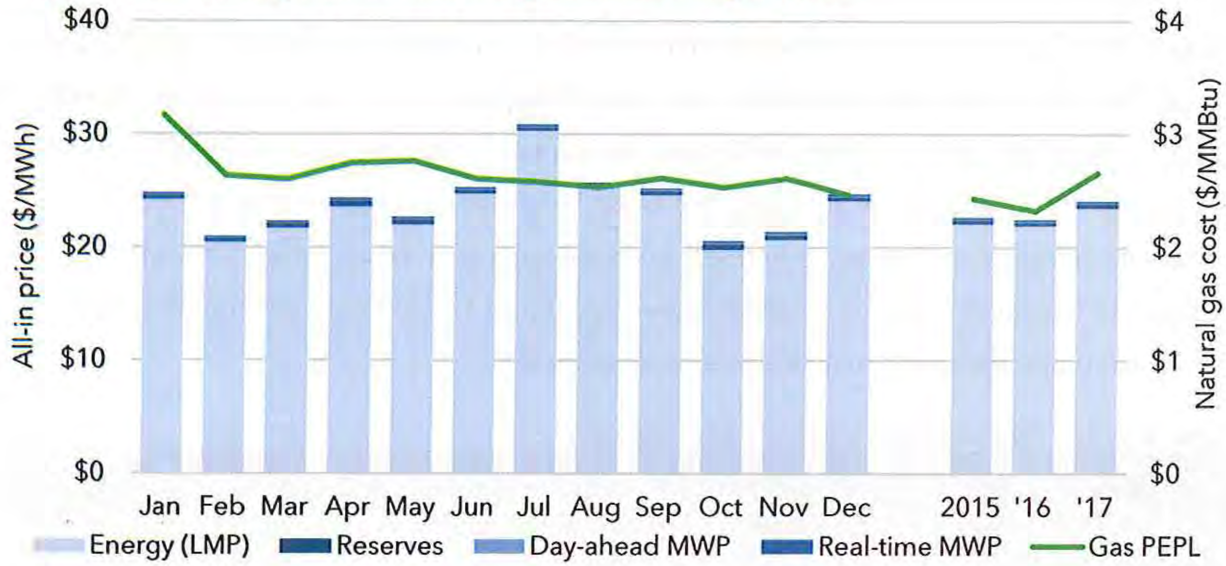
Additionally, there are other deviation calculations that are based on the difference of a unit in manual status output versus where they would be desired to run if the resource were dispatchable. When this happens there is a potential for the combined unit's desired energy to be lower than the physical minimum limit of the unit. This is because the settlement process calculates the desired energy quantities with the assumption that the unit can run at zero megawatts, which is below the physical minimum of the unit. As a result, the jointly-owned unit asset owners could have distribution charges unduly applied.

SPP, stakeholders, and the MMU are currently working on an approach to redesign the approach to jointly-owned units. Stakeholders have unofficially agreed on a design concept that they believe will address these issues and fulfill the MMU's original design gap recommendation. A new design approach is currently in the stakeholder process. This approach requires that jointly-owned units offer in as one unit. The market system will dispatch the resource as one unit, and then the settlements process will allocate the cost and revenues out by percentage of ownership of the resource.

4.4 TOTAL WHOLESALE MARKET COSTS

The average annual all-in price, which includes the costs of energy, day-ahead and real-time reliability unit commitment make-whole payments, operating reserves,[66] reserve sharing group costs, and payments to demand response resources, was $24.08/MWh in 2017. This compares to the average price of energy at load pricing nodes in SPP's real-time market for 2017 of $23.48/MWh.[67] The all-in price was just over seven percent higher than the 2016 average all-in price, which is partially related to the increase in natural gas prices.[68] Figure 4-42 plots the average all-in price of energy and the cost of natural gas, measured at the Panhandle Eastern (PEPL) hub.

Figure 4-42 All-in price of electricity and natural gas cost



The figure shows that the vast majority of costs are from the day-ahead and real-time energy markets.[69] The graph also shows that the market cost of operating reserves and make-whole payments constituted approximately two percent of the all-in price, with make-whole payments and operating reserves amounting to $0.27/MWh and $0.26/MWh, respectively.

[66] Operating reserves are resource capacity held in reserve for resource contingencies and NERC control performance compliance, which includes the following products: regulation-up service, regulation-down service, spinning reserve and supplemental reserve.
[67] The cost of energy includes all of the shortage pricing components.
[68] The Reserve Sharing Group costs and payments to demand response resources were negligible for both years.
[69] Shortage pricing is included in the energy component and not easily separated out in the SPP settlement data. See Section 4.2 for a discussion of shortage pricing impacts.

4.5 LONG-RUN PRICE SIGNALS FOR INVESTMENT

In the long term, efficient market prices provide signals for any needed investment in new transmission, generation, and ongoing maintenance of existing generation to meet load. Given the very high amount of capacity in the SPP system at peak, which the MMU estimates was about 30 percent in 2017 (see Section 2.3.2), the MMU does not expect market prices to support new entry of non-wind generation investments. In this context, the only explanation for wind and solar generation investments can be the federal and/or state subsidies for those resources.

The MMU conducted an analysis to determine if the SPP market would support investments in new generation by analyzing the fixed costs, and annual fixed operating and maintenance costs of three generation technologies relative to their potential net revenues[70] at SPP market prices. The plants considered include a scrubbed coal plant, a natural gas combined-cycle, and a combustion turbine. Figure 4-43 provides the cost assumptions and Figure 4-44 shows the results of the net revenue analysis. The analysis assumes the market dispatches the hypothetical resource when price exceeds the short-run marginal cost of production. In addition to these assumptions a capital recovery factor of 12.6 percent was used in the annual fixed operating and maintenance cost component.

Figure 4-43 Net revenue analysis assumptions

	Scrubbed coal	Advanced gas/oil combined-cycle	Advanced combustion Turbine
Size (MW)	650	429	237
Total overnight cost ($/kW-yr.)	$ 5,030	$ 1,094	$ 672
Variable overhead and maintenance ($/MWh)	$ 7.06	$ 1.99	$ 1.63
Fixed overhead and maintenance ($/kW-yr.)	$ 69.56	$ 9.94	$ 6.78
Heat rate (Btu/kWh)	9,750	6,300	9,800

Source: EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, January 2018

[70] Net revenue is equal to revenues minus estimated marginal cost.

Figure 4-44 Net revenue analysis results

Technology	Average marginal cost ($/MWh)	Net revenue from SPP market ($/MW yr.)	Annual revenue requirement ($/MW yr.)	Able to recover new entry cost	Annual fixed O&M cost ($/MW yr.)	Able to recover avoidable cost
Scrubbed coal	$ 27.73	$ 29,199	$ 701,205	NO	$ 69,560	NO
Advanced gas/oil combined-cycle	$ 18.75	$ 51,399	$ 147,320	NO	$ 9,940	YES
Advanced combustion turbine	$ 27.70	$ 29,036	$ 91,167	NO	$ 6,780	YES

Revenues have been insufficient to support the cost of new entry generation for all three technologies since the inception of the Integrated Marketplace, and 2017 was no exception. In 2015 and 2016, prices did support the ongoing maintenance cost of combined-cycle and combustion turbine units, though it did not support the cost of scrubbed coal units. This is consistent with the 2017 results shown above. Declining gas prices, excess capacity, and increasing negative prices are the leading contributors to the decline in the profitability of coal plants.

Figure 4-45 provides results by SPP resource zone, as indicated by the dominant utility in the area.

Figure 4-45 Net revenue analysis by zone

	Scrubbed coal			Gas/oil combined-cycle			Combustion turbine		
Resource Zone	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost
AEP	$ 19,459	NO	NO	$ 65,229	NO	YES	$ 41,761	NO	YES
KCPL	$ 12,031	NO	NO	$ 40,364	NO	YES	$ 29,741	NO	YES
NPPD	$ 8,688	NO	NO	$ 26,780	NO	YES	$ 24,889	NO	YES
OGE	$ 16,002	NO	NO	$ 55,802	NO	YES	$ 35,653	NO	YES
SPS	$ 11,715	NO	NO	$ 40,501	NO	YES	$ 34,587	NO	YES
WAUE	$ 15,740	NO	NO	$ 52,569	NO	YES	$ 10,717	NO	YES
WR	$ 10,822	NO	NO	$ 38,664	NO	YES	$ 30,612	NO	YES

This shows that the conclusions do not vary geographically, even with differing energy prices and fuel costs. Other RTO/ISO markets have experienced a "missing money problem" in their markets, where net revenues do not support needed new investments. The MMU expects the market to signal the retirement of inefficient generation. Aging of the fleet will eventually change the peak available capacity such that price signals for higher net revenue become increasingly important. The ability of market forces to provide these incentives and long-run price signals is a strong benefit of the Integrated Marketplace.

4.6 MUST-OFFER PROVISION

The Integrated Marketplace has a limited day-ahead must-offer provision that was intended to incentivize load-serving entities to participate in the day-ahead market. Market participants that are non-compliant are assessed a penalty based on the amount of available capacity available in the day-ahead market relative to the market participant's real-time load. The requirement is limited in the sense that only market participants with generation assets that serve load are subject to the rules. Load-serving market participants that offer enough generation, and/or provide scheduling information indicating a firm power purchase to cover at least 90 percent of their real-time load are not subject to a penalty. An alternative way to satisfy the provision is to offer all generation that is not on outage. No penalties were assessed in 2017.

In 2014, the MMU recommended that SPP simultaneously eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance based on the premise that the recommended penalty provision would be sufficient to ensure an efficient level of participation in the day-ahead market.

Market participants approved a proposal to eliminate the current limited day-ahead must-offer provision of the SPP tariff in late 2015.[71] The removal of the day-ahead must-offer was then tabled by the SPP stakeholders until the Market Working Group completed its review of the physical withholding revisions proposed by the MMU. The MMU engaged the Market Working Group in a discussion on conduct thresholds and impact test requirements for physical withholding penalties, in conjunction with establishing a formula-based penalty structure.[72] As a result of those discussions, the market monitor developed several

[71] RR 125 (Removal of day-ahead limited must-offer) was approved by the Market Working Group in October 2015.
[72] The market monitor submitted RR 135 (Revision of physical withholding rules) to the Market Working Group in December 2015.

modifications to the proposal.[73] The final proposal adjusted the physical thresholds and changed the measurement of financial impact so that it did not require off-line market case re-runs. This final proposal was rejected by the SPP stakeholders.[74] SPP stakeholders then approved the removal of the day-ahead must-offer with no additional physical withholding provisions, and SPP filed the tariff revision with FERC in the summer of 2017. FERC denied the removal of the limited must-offer requirement as it did not include physical withholding non-compliance penalties.[75]

The MMU continues to recommend updating the day-ahead must offer requirement and addressing FERC's concerns. However, given the status of other higher priority initiatives, the MMU assigns a low priority to addressing the issue at this time. See further discussion in Chapter 7.

[73] The market monitor submitted RR 204 (Physical withholding) to the Market Working Group in December 2016.
[74] RR 204 rejected by Market Working Group in February 2017.
[75] See FERC ruling at https://www.ferc.gov/CalendarFiles/20171013130834-ER17-2312-000.pdf

5 CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

5.1 TRANSMISSION CONGESTION

The locational marginal price (LMP) for the almost 20,000 pricing nodes in the SPP market reflects the sum of three components:

1) marginal energy component (MEC) - system-wide marginal cost of the energy required to serve the market,
2) marginal congestion component (MCC) - the marginal cost of any increase or decrease in energy at a location with respect to transmission constraints, and
3) marginal loss component (MLC) - the marginal cost of any increase or decrease in energy to minimize system transmission losses.

$$LMP = MEC + MCC + MLC$$

LMPs are a key feature of electricity markets that ensure the efficient scheduling, commitment, and dispatch of generation given the system load and reliability constraints. LMPs also provide price signals for efficient incentives for future generation and transmission investment and help guide retirement decisions.

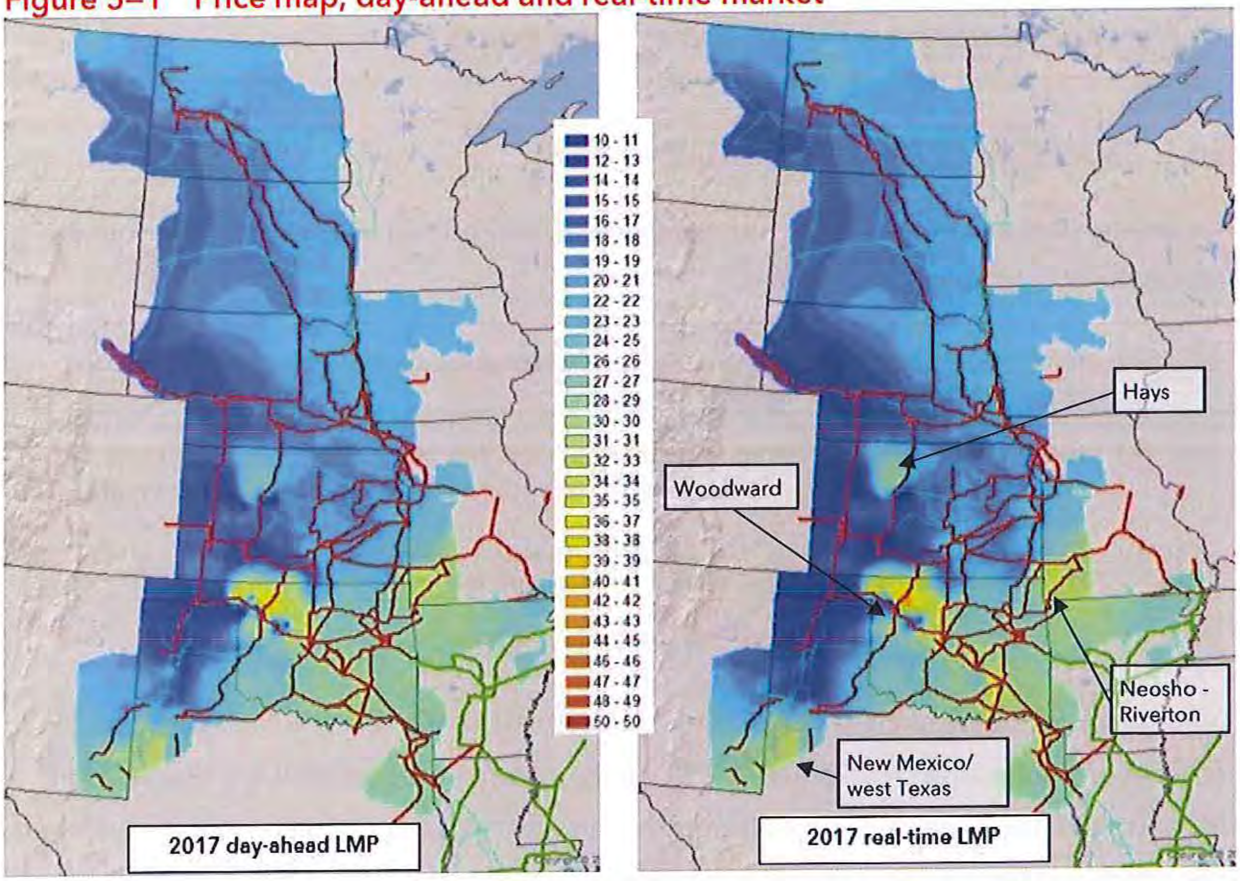
This section focuses on the congestion and loss components of price and related items including:

- geographic pattern of congestion and losses,
- changes in the transmission system that alter congestion patterns;
- congestion impacts on local market power,
- load-serving entities hedging congestion costs in the transmission congestion rights market, and
- distribution of marginal congestion and loss amounts.

5.1.1 PRICING PATTERNS AND CONGESTION

Figure 5–1 shows price contour maps representing the day-ahead and real-time average prices in 2017.

Figure 5–1 Price map, day-ahead and real-time market



Annual average day-ahead market prices ranged from around $18/MWh on the western edge of the SPP footprint, to around $36/MWh in the Woodward area of northwest Oklahoma. 2017 continued to see higher prices ($31/MWh) in the New Mexico and west Texas area, as well as around Hays, Kansas ($26/MWh). About 74 percent of this price variation can be attributed to congestion and 26 percent to marginal losses, which is consistent with prior years. Because congestion is more volatile in the real-time market, the average geographic price range is slightly larger, from $12/MWh to $42/MWh for real-time market prices versus $16/MWh to $37/MWh for day-ahead prices.

In May 2017, upgrades were made at Woodward by adding a 138kV phase-shifting transformer. This area was the most frequently constrained area in the SPP market before the upgrade. However, since the phase-shifting transformer has been in service, the frequency of congestion at Woodward has fallen significantly such that the MMU recommended no longer designating Woodward as a frequently constrained area.[76] This upgrade has allowed higher

[76] Frequently constrained areas are discussed further in Section 5.1.6.

levels of low-cost wind generation in the western parts of the SPP footprint to serve load centers located on the eastern portion of SPP. This is evident with continuing wind peak records for 2017, the latest being 15,690 MW set on December 15.

5.1.2 CONGESTION BY GEOGRAPHIC LOCATION

The major drivers of the congestion pattern in SPP are the physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, and the geographic differences in fuel costs. The eastern side of the SPP footprint, with a higher concentration of load, also has a higher concentration of high-voltage (345 kV) transmission lines. Historically, high-voltage connections between the west and east have been limited, as have high-voltage connections into the Texas Panhandle area.

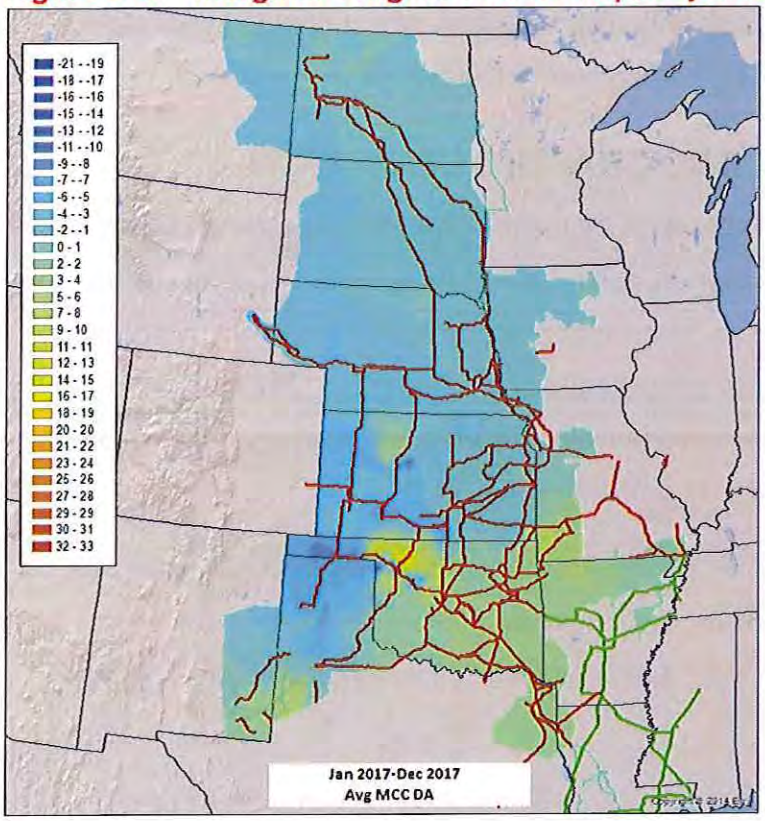
The cost of coal increases as transportation cost rises. Transportation cost increases with distance from the Wyoming Powder River Basin near the northwest corner of SPP's footprint. This is important because coal is SPP's predominant fuel for energy generation at 46% in 2017.

Natural gas-fired generation, SPP's largest fuel type by installed capacity (42 percent in 2017), resides predominantly in the southern portions of SPP. Wind-powered generation generally lies in the western half of the footprint, and nuclear generation resides near the center, while the majority of hydro is located in the north.

These factors combine to create a general northwest-southeast split in prices. The exception is slightly higher prices in the northern area of North Dakota resulting from the growth of, and associated demand from, oil and gas exploration and production facilities. Outside of the extreme northern part of North Dakota, the Integrated System typically sees lower prices compared to the rest of the footprint.

Figure 5–2 depicts the average marginal congestion component for the day-ahead market across the SPP footprint.

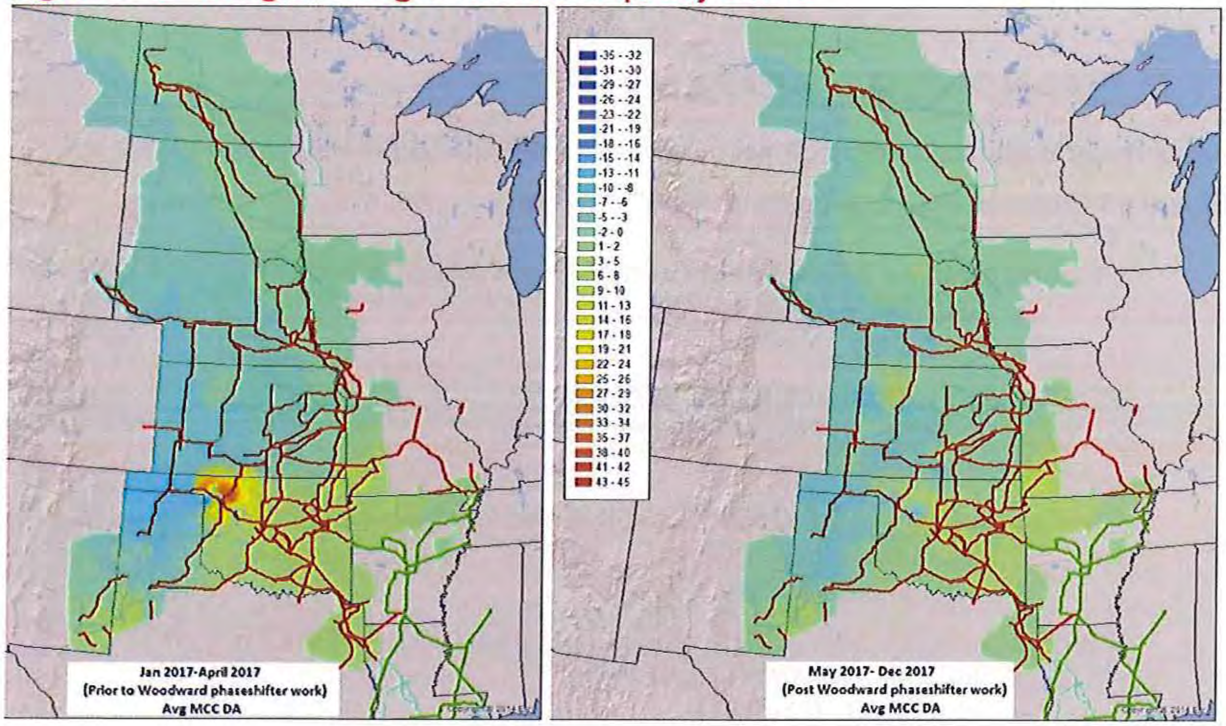
Figure 5–2 Marginal congestion cost map, day-ahead market



The lowest average marginal congestion costs occur in the Oklahoma and Texas Panhandle region, at -\$7/MWh, and the highest marginal congestion costs lie in the Woodward, Oklahoma area at \$16/MWh, and the New Mexico and west Texas areas at \$9/MWh.

The congestion in the Woodward area was persistent in 2017 until the phase-shifting transformer upgrade went into place in May 2017. Figure 5–3 shows the average marginal congestion component for January through April prior to the upgrade, and May through December after the upgrade.

Figure 5–3 Marginal congestion cost map, day-ahead



With the addition of the phase-shifting transformer at Woodward, the congestion has shifted east, but is not as evident as the prior Woodward constraint. This upgrade was in place just before the summer which is typically the lower wind season in SPP, but new wind peaks occurred later in 2017. The Texas Panhandle congestion still remains but has moved further south towards the Lubbock, Texas area.

5.1.3 TRANSMISSION EXPANSION

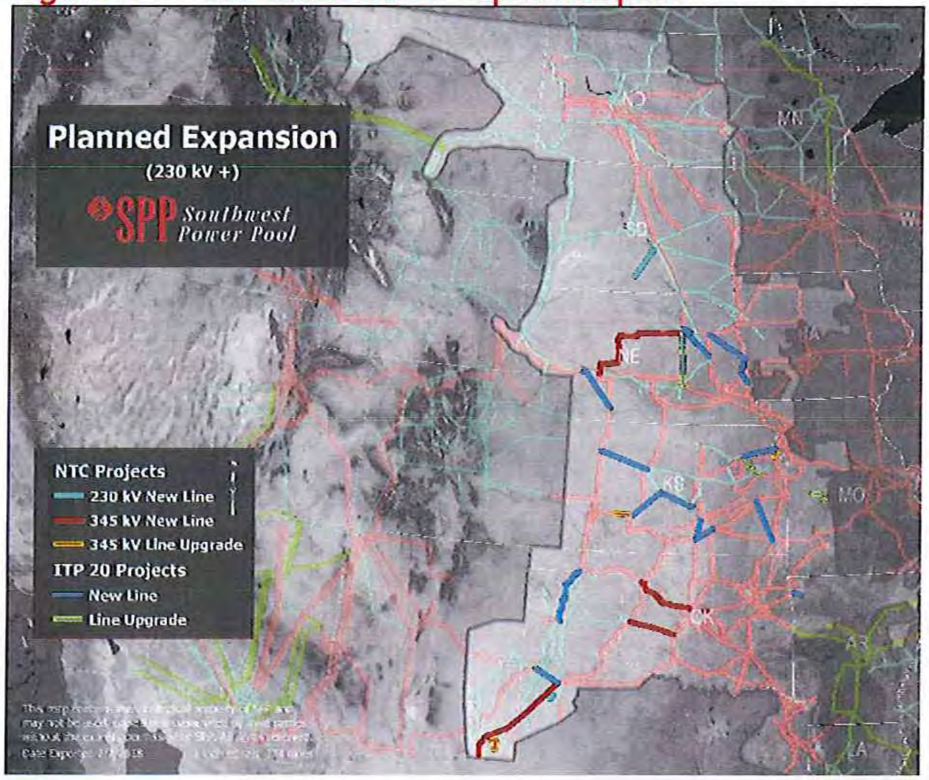
Several major transmission projects were completed during 2017 that will support the efficient transmission of energy across the SPP footprint.[77]

- East Manhattan - Jeffrey Energy Center 230 kV (circuit 1) rebuild
  - location: eastern Kansas
  - energized: April 2017
- Fort Smith transformer 500/161 kV (circuit 5)
  - location: Arkansas/Oklahoma border
  - energized: July 2017
- Mingo transformer 345/115 kV (circuit 2) and terminal upgrades
  - location: western Kansas
  - energized: January 2017
- Woodward extra high voltage phase-shifting transformer 138kV (circuit 1)
  - location: western Oklahoma
  - energized: May 2017

The lines depicted on the map in Figure 5–4 below are projects that will further enhance the SPP transmission grid. The Integrated Transmission Plan (ITP) projects shown are recommended upgrades to the extra-high-voltage backbone (345kV and above) for a 20-year horizon. The ITP process seeks to target a reasonable balance between long-term transmission investments and congestion costs to customers. The notification to construct (NTC) and ITP projects shown have received a written notice from SPP to construct a transmission project that was approved by the SPP board of directors. Planned projects that may provide relief for the most congested areas in SPP are listed in Figure 5–10.

[77] See the 2018 SPP Transmission Expansion Plan Report at https://www.spp.org/documents/56611/2018_spp_transmission_expansion_plan_report.pdf

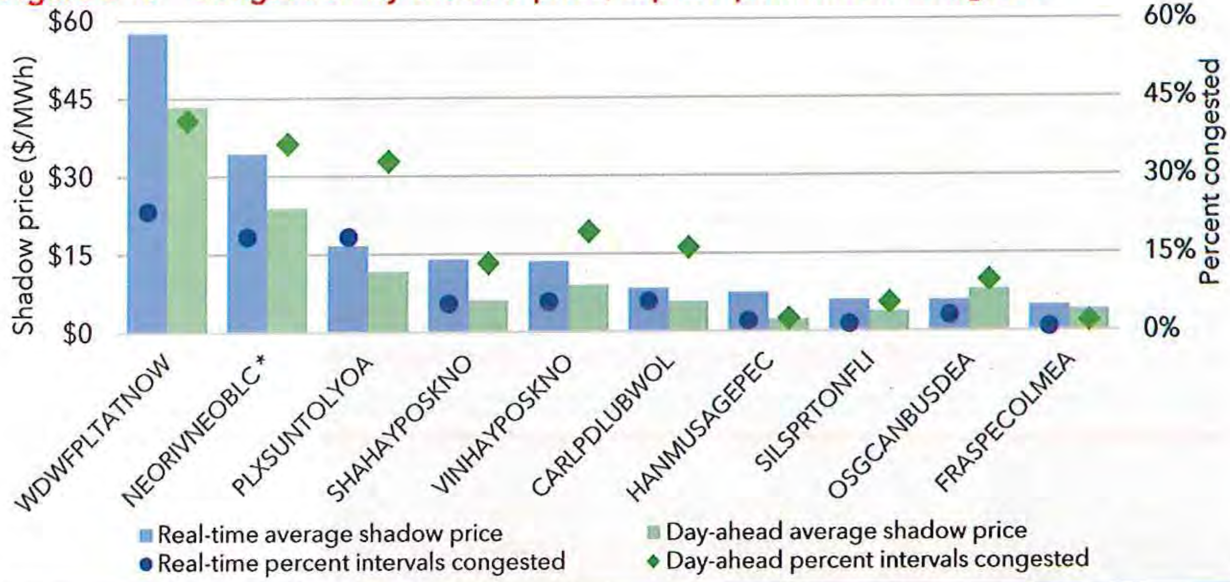
Figure 5–4 SPP transmission expansion plan



5.1.4 TRANSMISSION CONSTRAINTS

Market congestion reflects the economic dispatch cost of honoring transmission constraints. SPP uses these constraints to manage the flow of energy across the physical bottlenecks of the grid in the least costly manner while ensuring reliability. In doing so, SPP calculates a shadow price for each constraint, which indicates the potential reduction in the total market production costs if the constraint limit could be increased by one megawatt for one hour. Figure 5–5 provides the top 10 permanent flowgate constraints by shadow price for 2017. Temporary flowgate constraints are excluded from this graph as in previous annual and quarterly reports. Because of the increase of congestion seen on temporary flowgate constraints, the 2018 winter quarterly report will begin to include these constraints.

Figure 5–5 Congestion by shadow price, top ten permanent flowgates



Flowgate name	Region	Flowgate location
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)
NEORIVNEOBLC *	SW Missouri/SE Kansas	Neosho-Riverton (161) ftlo Neosho-Blackberry (345)
PLXSUNTOLYOA	West Texas (Lubbock)	Plant X Sub-Sundown (230) ftlo Tolk Sub-Yoakum (230)
SHAHAYPOSKNO	Western Kansas	South Hays-Hays (115) ftlo Post Rock-Knoll (230)
VINHAYPOSKNO	Western Kansas	Vine-Hays (115) ftlo Post Rock-Knoll (230)
CARLPDLUBWOL	West Texas (Lubbock)	Carlisle-Doud (115) ftlo Lubbock South-Wolfforth (230)
HANMUSAGEPEC	Eastern Oklahoma	Hanncock-Muskogee (161) ftlo Agency-Pecan Creek (161)
SILSPRTONFLI	NW Arkansas	Siloam-Siloam Springs (161) ftlo Tonnence-Flint Creek (345)
OSGCANBUSDEA	Texas Panhandle (Amarillo)	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)
FRASPECOLMEA	S Dakota/Nebraska border	Ft Randall-Spencer (115) ftlo Meadow Grove-Kelly (230)

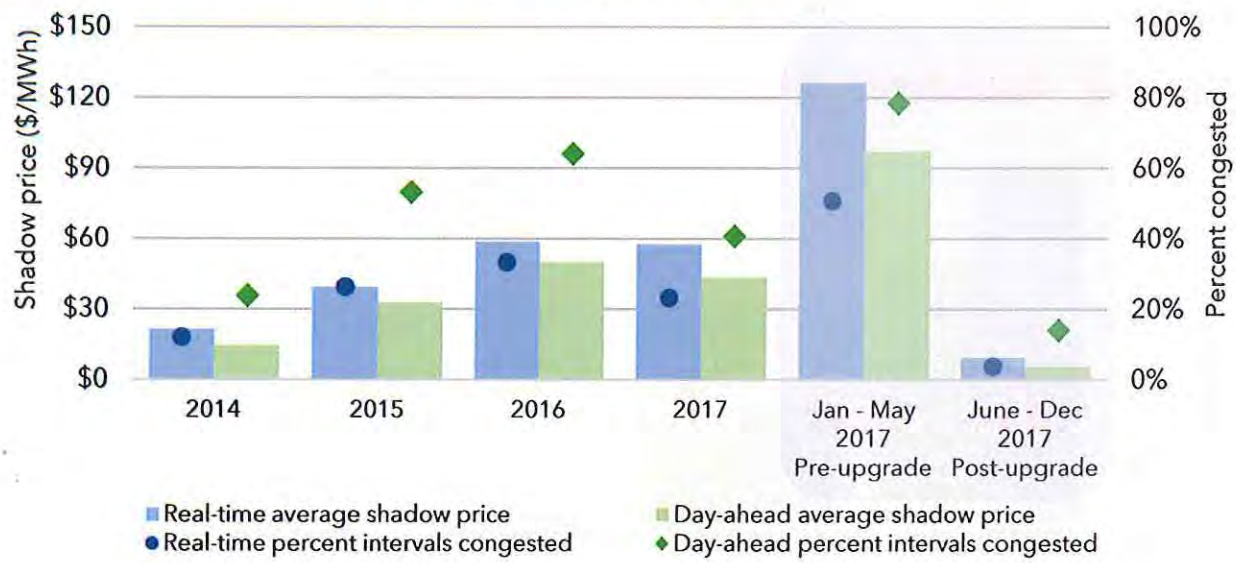
* SPP market-to-market flowgate

Most of the congested corridors on the system are significantly impacted by inexpensive wind generation. The three areas most affected by wind generation are the west-to-east flows through the Woodward, Oklahoma area, the north-to-south flows through west Texas, and the Texas Panhandle, and the flows through western Kansas. The second most congested area is the southwest Missouri/southeast Kansas area, and is also impacted by wind and external flows. Projects are planned throughout the SPP footprint that provide for more transfer of wind generation from west to east and are listed in Figure 5–10. Constraints in all other areas of the footprint are congested less than 10 percent of all intervals in both the day-ahead and real-time markets.

5.1.4.1 Western Oklahoma constraints

Significant upgrades have been made to move more energy from the wind generation corridor in the west to the load centers in the east. Extensive buildout of the extra-high-voltage system can result in complications on the lower voltage system, as seen in the Woodward area since 2014, driving the need for further upgrades. Even with the phase-shifting transformer upgrade at Woodward in May 2017, the Woodward constraint was still the most congested constraint in 2017 with 40 percent of all intervals congested in the day-ahead market and 23 percent of all intervals in real time. Figure 5–6 compares congestion on the Woodward constraint from 2014 through 2017, and also shows a breakdown of congestion before and after the phase-shifting transformer upgrade in May 2017.

Figure 5–6 Woodward congestion pre-/post-upgrade

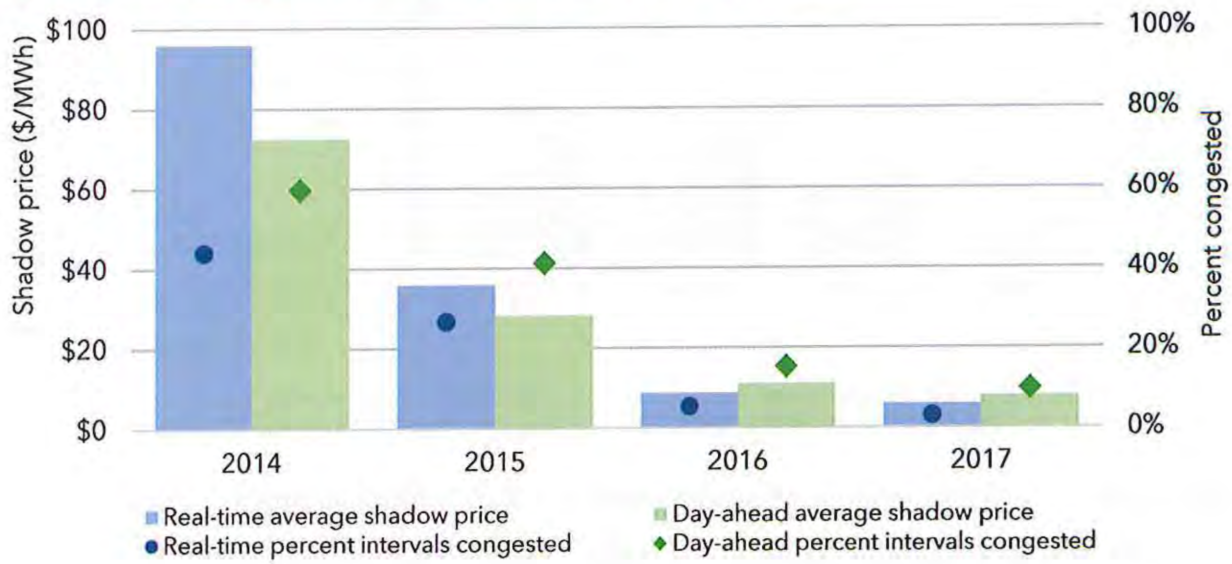


The yearly average shadow prices for both markets in 2017 remained similar to those in 2016, but as seen in Figure 5–6, most of the congestion in 2017 occurred prior to the upgrade in May. The Woodward constraint was congested during 79 percent of all day-ahead intervals prior to the upgrade and only 14 percent after. In the real-time market it was congested during 50 percent of all intervals prior to the upgrade and less than four percent after. New wind peaks occurred in late 2017 indicating higher transfers of wind generation after the upgrade.

5.1.4.2 West Texas and Texas Panhandle constraints

The west Texas and Texas Panhandle between Amarillo and Lubbock down into southeast New Mexico was the most congested transmission corridor at the start of the SPP market. This corridor is impacted by the predominantly natural gas-fired generation in the south that is more expensive than the wind generation to the north. This corridor still remains, but transmission upgrades have resulted in congestion now more prevalent further south in this area. The MMU reflected this change in the latest frequently constrained area report.[78] The Plant X Sub - Sundown 230kV flowgate had the highest real-time market average shadow price for this area at $16/MWh in 2017. The Osage Switch - Canyon East 115kV flowgate was predominantly the most congested constraint in SPP since the beginning of the market. Figure 5–7 compares congestion on the Osage Switch - Canyon East 115kV constraint since the start of the SPP market in 2014.

Figure 5–7 Osage Switch - Canyon East 115kV congestion



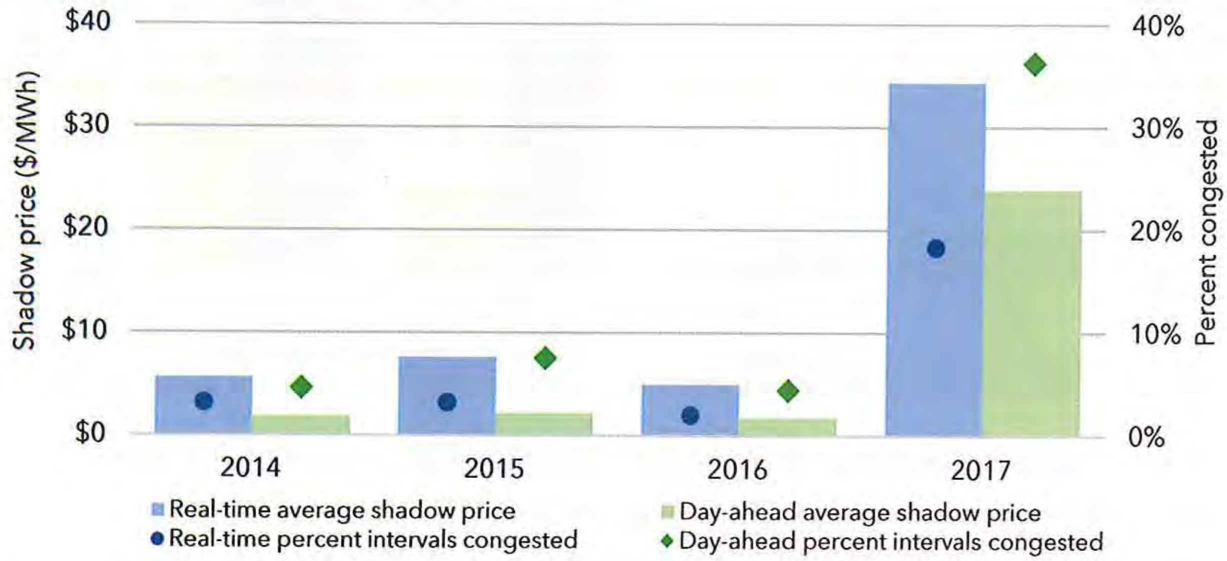
Both the magnitude and frequency of congestion on the Osage Switch - Canyon East 115kV constraint has decreased in both markets because of transmission upgrades. Congestion has moved further south where more prevalent congestion exists on the Plant X Sub - Sundown 230kV flowgate as shown in Figure 5–5.

[78] https://www.spp.org/Documents/56330/FCA%202017%20Report%20-%20FINAL.pdf

5.1.4.3 Southwest Missouri/Southeast Kansas constraints

The Neosho - Riverton 161kV constraint is a market-to-market flowgate that is impacted by SPP and MISO wind, as well as flows from neighboring non-market areas.[79] Congestion in this area dates back to prior to the start of the Integrated Marketplace. However, continued addition of wind in SPP and neighboring areas have contributed to the increased congestion. Figure 5–8 compares congestion on the Neosho - Riverton 161kV constraint since 2014.

Figure 5–8 Neosho - Riverton 161kV congestion



Congestion increased substantially on this constraint in 2017 when compared to previous years. Since the upgrade to the Woodward area, this area has been one of the top congested constraints during high wind months. This constraint has been a focus of seams discussions on the amount of market-to-market payments, power swings or volatility, and transmission upgrades that may benefit SPP, MISO, and other neighboring non-market entities. The market-to-market process has settled over $18 million in payments for the Neosho-Riverton constraint from MISO to SPP, and is discussed in Section 2.6.2.

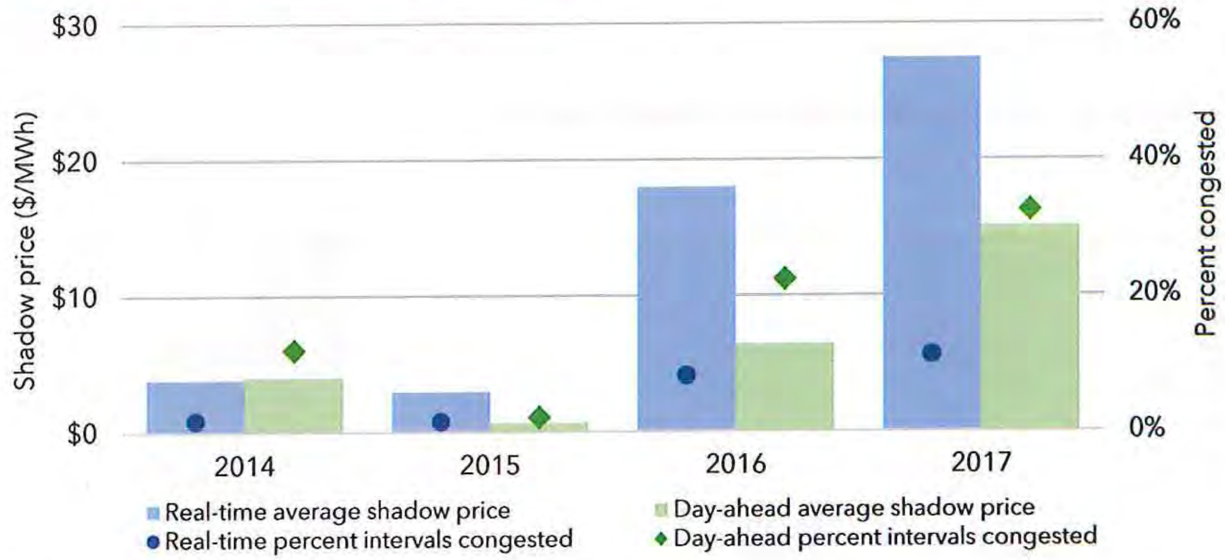
5.1.4.4 Western Kansas constraints

The Hays, Kansas area is also impacted by wind generation and several constraints have appeared consistently since prior to the start of the SPP market. The South Hays - Hays 115kV constraint was terminated in May 2017 and later was replaced with the Vine - Hays

[79] Neighboring non-markets include; Tennessee Valley Authority, Associated Electric Cooperative Inc., and Southwestern Power Administration

115kV constraint. Figure 5–9 compares congestion on the South Hays - Hays 115kV constraint since start of the SPP market. The values for South Hays - Hays 115kV and Vine - Hays 115kV are combined in the 2017 results.

Figure 5–9 Hays, Kansas congestion[80]



For 2017, the Hays, Kansas area continues to see an increase in congestion. These two constraints experienced congestion in over 32 percent of all intervals in the day-ahead market and 11 percent of all intervals in the real-time market. The yearly average shadow price for the real-time market was $27/MWh for 2017 compared to $18/MWh in 2016.

5.1.5 PLANNED TRANSMISSION PROJECTS

Figure 5–10 provides a list of projects that may alleviate congestion on the 10 most congested flowgates in the SPP system.

[80] Values combined for SHAHAYPOSKNO (South Hays - Hays 115kV) and VINHAYPOSKNO (Vine - Hays 115kV) constraints for 2017. South Hays - Hays 115kV terminated May 2017, and Vine - Hays 115kV activated September 2017.

Figure 5–10 Top ten congested flowgates with projects

Flowgate name	Region	Flowgate location	Projects that may provide relief
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)	1. Matthewson-Tatonga 345 kV Ckt 2 (February 2018, 2012 ITP10) 2. Tatonga-Woodward 345kV Ckt 2 (February 2018, 2012 ITP10) 3. Degrasse 345/115 kV tap on Woodward-Thistle 345 kV (June 2019, 2016 ITPNT)
NEORIVNEOBLC *	SW Missouri/SE Kansas	Neosho-Riverton (161) ftlo Neosho-Blackberry (345)	Neosho - Riverton 161kV Terminal Upgrades (June 2018, 2017 ITP10)
PLXSUNTOLYOA	West Texas (Lubbock)	Plant X Sub-Sundown (230) ftlo Tolk Sub-Yoakum (230)	1. Matthewson-Tatonga 345 kV Ckt 2 (February 2018, 2012 ITP10) 2. Tatonga-Woodward 345kV Ckt 2 (February 2018, 2012 ITP10) 3. Degrasse 345/115 kV tap on Woodward-Thistle 345 kV (June 2019, 2016 ITPNT)
SHAHAYPOSKNO	Western Kansas	South Hays-Hays (115) ftlo Post Rock-Knoll (230)	Post Rock–Knoll 230kV Ckt 2 (Jan 2019, 2017 ITP10)
VINHAYPOSKNO	Western Kansas	Vine-Hays (115) ftlo Post Rock-Knoll (230)	Post Rock–Knoll 230kV Ckt 2 (Jan 2019, 2017 ITP10)
CARLPDLUBWOL	West Texas (Lubbock)	Carlisle-Doud (115) ftlo Lubbock South-Wolfforth (230)	1. Carlisle-Wolfforth 230 kV Ckt 1 (March 2018, 2013 ITPNT) 2. Yoakum-Hobbs 230/115 kV Tap (December 2019, 2016 ITPNT / 2017 ITP10) 3. Tuco-Yoakum 345 kV Ckt 1 (December 2019, 2014 High Priority / 2016 ITPNT / 2016 AG1)
HANMUSAGEPEC	Oklahoma city area	Hanncock-Muskogee (161) ftlo Agency-Pecan Creek (161)	No projects identified at the time of report publication.
SILSPRTONFLI	NW Arkansas	Siloam-Siloam Springs (161) ftlo Tonnence-Flint Creek (345)	No projects identified at the time of report publication.
OSGCANBUSDEA	Texas Panhandle (Amarillo)	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)	1. Carlisle-Wolfforth 230 kV Ckt 1 (March 2018, 2013 ITPNT) 2. Tuco-Yoakum 345 kV Ckt 1 (December 2019, 2014 High Priority / 2016 ITPNT / 2016 AG1) 3. Yoakum-Hobbs 345 kV Ckt 1 (June 2020, 2014 High Priority)
FRASPECOLMEA	Eastern SD / Nebr border	Ft Randall-Spencer (115) ftlo Meadow Grove-Kelly (230)	No projects identified at the time of report publication.

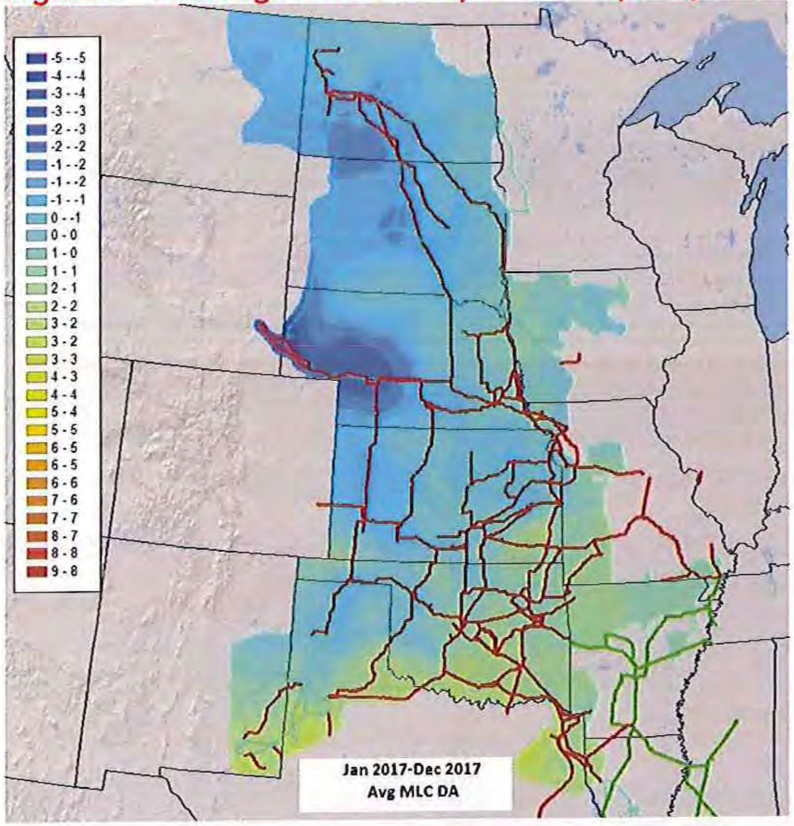
* SPP market-to-market flowgate

5.1.6 GEOGRAPHY AND MARGINAL LOSSES

Variable transmission line losses decrease with increased line voltage or decreased line length for the same amount of power moved. In the SPP footprint, much of the low-cost generation resides at a distance from the load and with limited high-voltage interconnection. The average variable losses on the SPP system for 2017 were 2.7 percent in the day-ahead market. This is up from 2.3 percent in 2016. The marginal loss component of the price captures the change in the total system cost of losses with an additional increment of load at a particular location relative to the reference bus.

Figure 5–11 maps the annual average day-ahead market marginal loss components.

Figure 5–11 Marginal loss component map, day-ahead



The average day-ahead marginal loss component ranges from about -\$3.55/MWh at the Laramie River Station in eastern Wyoming, to -\$2.80/MWh near North Platte, Nebraska, to -\$0.30/MWh in the Kansas City area, to \$0.60/MWh in the Hobbs, New Mexico area, and up to \$1.70/MWh in the southeast corner of New Mexico. Negative values reduce prices through the marginal loss component relative to the marginal energy cost. Positive values increase prices as generation from these locations are more beneficial from a marginal loss perspective. These values were very similar compared to the results in 2016.

5.1.7 FREQUENTLY CONSTRAINED AREAS AND LOCAL MARKET POWER

Congestion in the market creates local areas where only a limited number of suppliers can provide the energy to serve local load without overloading a constrained transmission element. Under these circumstances, the pivotal suppliers have local market power and the ability to raise prices above competitive levels thereby extracting higher than normal profits from the market. SPP's tariff provides provisions for mitigating the impact of local market power on prices, and the effectiveness of market power mitigation is described in Chapter 6. Local market power can be either transitory, as is frequently the case with an outage, or persistent, when a particular load pocket is frequently import-constrained.

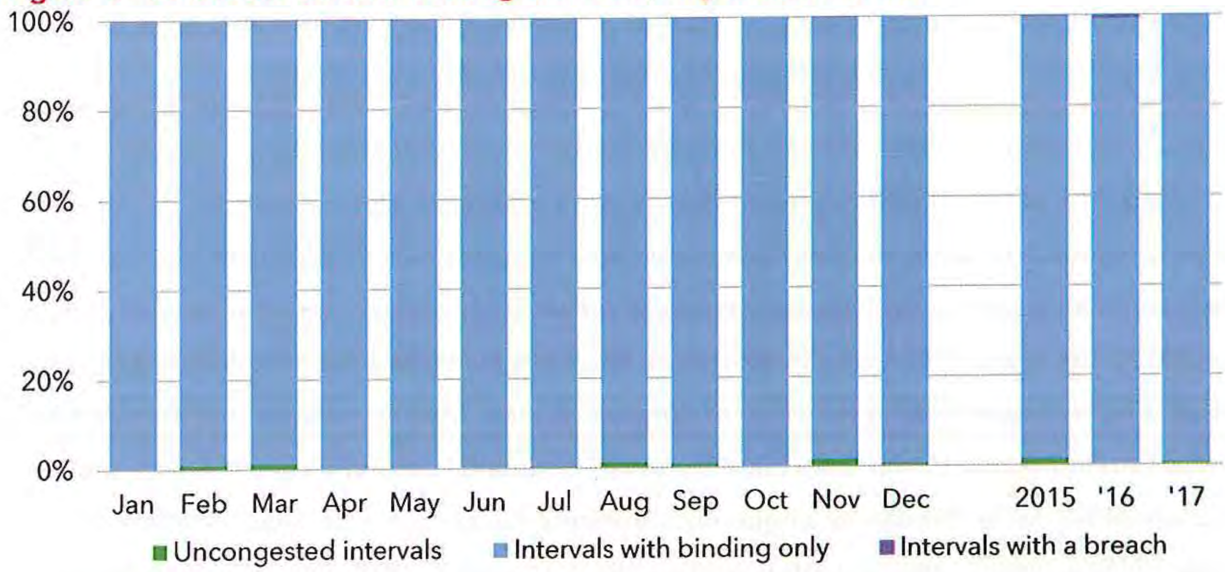
Because the SPP tariff calls for more stringent market power mitigation for frequently constrained areas, the MMU analyzes market data at least annually to assess the appropriateness of the frequently constrained area designations. The Woodward and Texas Panhandle areas remained frequently constrained areas, as recommended in the 2016 study, for 2017. The latest 2017 study identified the decrease in congestion in the Woodward area related to the phase-shifting transformer upgrade in May. Shifting congestion patterns led to the recommendation to eliminate the Woodward frequently constrained area and to reduce the size of the Texas Panhandle frequently constrained area. SPP filed a report with FERC in early 2018, and FERC approved the changes effective April 1, 2018. The final reports are available on the SPP web page.[81]

5.1.8 MARKET CONGESTION MANAGEMENT

In optimizing the flow of energy to serve the load at the least cost, the SPP market makes extensive use of the available transmission up to constraint limits. When constraints reach their limits, they are considered binding. The market occasionally allows transmission lines to exceed their rating if the price to correct the overload becomes too high. This is considered a breached constraint. Figure 5–12 highlights day-ahead market binding, breached, and uncongested intervals.

[81] The reports can be found on the SPP website: https://www.spp.org/spp-documents-filings/?id=25496.

Figure 5–12 Breached and binding intervals, day-ahead market

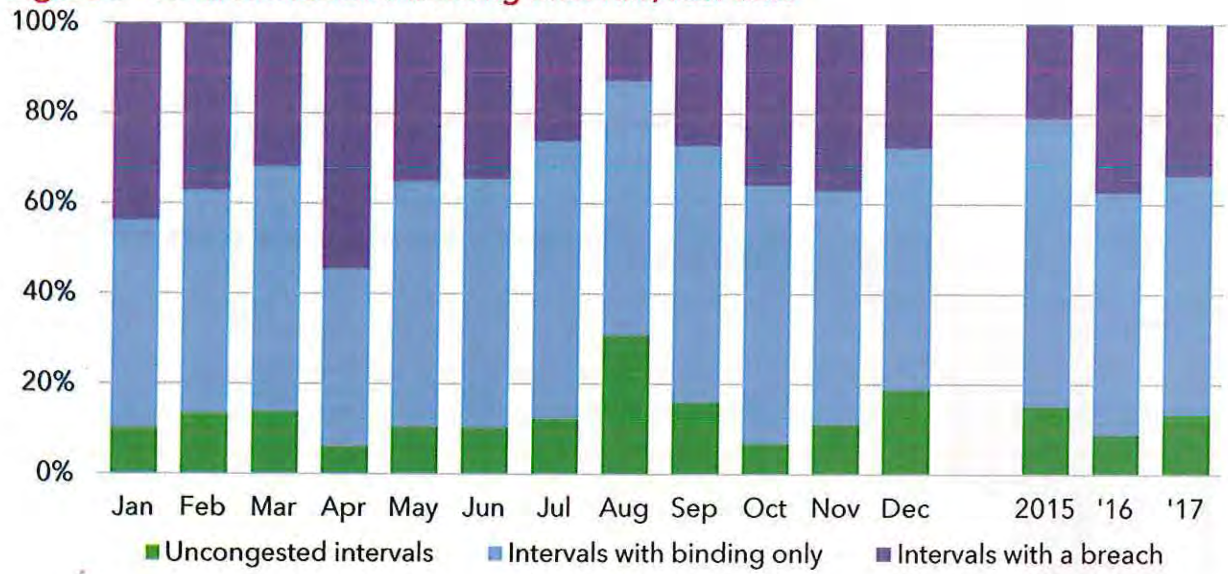


The figure shows that uncongested intervals and breached intervals are rare day-ahead. Historically in the Integrated Marketplace, less than one percent of day-ahead market intervals incur a breached condition compared to nearly 25 percent for the real-time market.[82]

In the more dynamic environment of the real-time market, uncongested intervals and breached intervals occur much more frequently than in the day-ahead market. Real-time congestion is shown in Figure 5–13.

[82] SPP uses hourly intervals in the day-ahead Market and five minute intervals in the real-time market for scheduling, dispatch, and settlement purposes.

Figure 5–13 Breached and binding intervals, real time



Uncongested intervals were about 13 percent of intervals for 2017, compared to nine percent in 2016, and 15 percent in 2015. Intervals with a constraint breach were at 34 percent for 2017, down slightly from 37 percent in 2016, and higher than the 21 percent in 2015.

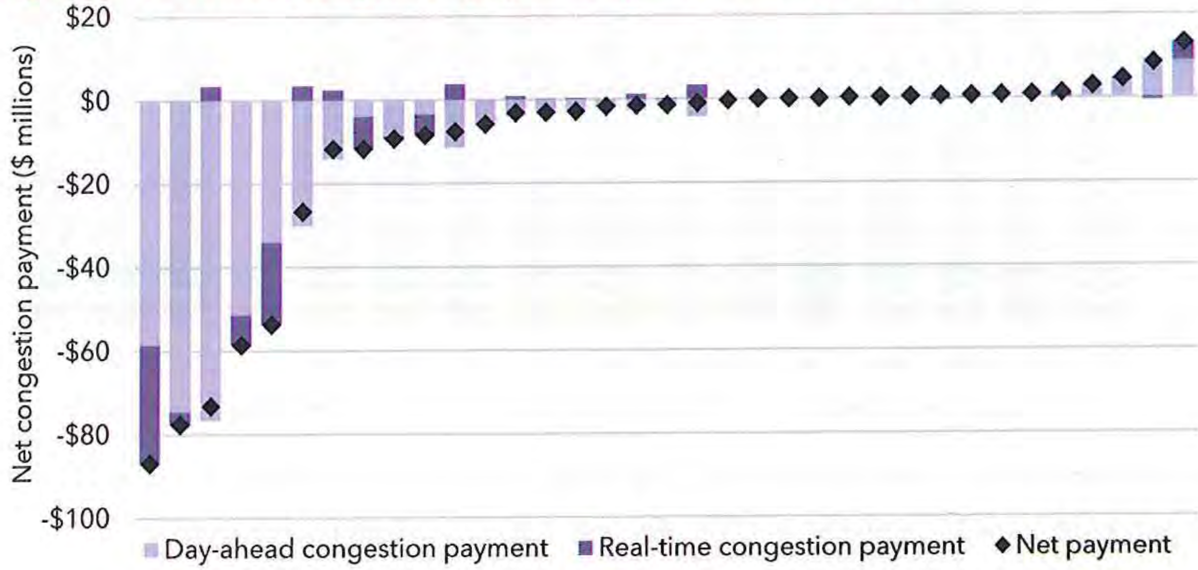
Market-to-market coordination with MISO, as discussed in Section 2.6.2, was implemented in March 2015, and the integration of the Integrated System occurred in October of that year, both of which increased the number of constraint breaches. A market-to-market breach of a MISO constraint could be an indicator that MISO has more efficient generation than SPP to alleviate congestion on that constraint.

5.1.9 CONGESTION PAYMENTS AND UPLIFTS

Market participants in the energy market incur congestion costs and receive congestion payments based on their marginal impact on total market congestion cost through the marginal congestion component of price. Most SPP market participants owning physical assets are vertically integrated, so their net congestion cost depends on two things. The first is whether they are a net buyer or seller of energy. The second is the relative marginal cost component at their generation and load. For financial market participants, congestion costs reflect the impact of virtual positions on a binding or breached constraint in the day-ahead and real-time markets.

Figure 5–14 shows the annual day-ahead and real-time market congestion payments for load-serving market participants during 2017.

Figure 5–14 Annual congestion payment by load-serving entity



Most load-serving entities face congestion costs, depicted as negative payments (charges) in the graph, because they are part of vertically-integrated entities with higher marginal congestion components at load than at resources. Day-ahead congestion payments by ranked load-serving entities ranged from almost $9 million in payments to about $76 million in charges.[83]

Market participants also receive payments and incur costs for real-time market congestion, which are charged and paid based on deviations between day-ahead and real-time market positions. At an aggregate level, absent the additional revenue neutrality uplift costs, 88 percent of the SPP load-serving entities' net congestion costs were hedged with day-ahead prices. Figure 5–15 provides the aggregate congestion costs and hedging totals for load-serving entities, non-load-serving entities, and financial only entities.

[83] Day-ahead congestion collections funds transmission congestion rights. These rights are described in greater detail in Section 5.2.

Figure 5–15 Total congestion payments

(in $ millions)	Load-serving entities			Non-load-serving and financial only entities		
	2015	2016	2017	2015	2016	2017
DA congestion	$ (148.6)	$ (259.6)	$ (364.6)	$ (31.5)	$ (81.2)	$ (219.0)
RT congestion	(3.4)	(20.4)	(48.3)	40.1	63.7	126.1
Net congestion	(152.0)	(280.0)	(412.9)	8.6	(17.5)	(92.9)
RT congestion uplift	(20.8)	(39.4)	(67.8)	(5.4)	(4.0)	(10.0)

Real-time market congestion ranged from over $4 million in payments to over $28 million in costs for load-serving entities. These ranges were from $2 million in payments to $38 million in costs for asset owning non-load-serving entities. Many of the non-load-serving entities incurring costs represent wind farms, which may sell at negative prices or buy back day-ahead market positions. The real-time market congestion payments result in a net positive $70 million for non-load-serving entities. Total real-time market congestion payments for non-load-serving and financial only entities totaled $126 million.

Unlike day-ahead congestion, which funds transmission congestion rights, real-time market congestion costs are allocated to market participants through revenue neutrality uplift (RNU) charges. In 2017, SPP allocated about 87 percent of revenue neutrality uplift charges to load-serving entities, resulting in an additional $68 million in congestion-related charges for load-serving entities.[84]

5.1.10 DISTRIBUTION OF MARGINAL LOSS REVENUES (OVER-COLLECTED LOSSES)

Both the congestion and loss components of prices create excess revenues for SPP that must be distributed to market participants in an economically efficient manner. In the case of marginal loss revenues, this requires that the distribution does not alter market incentives. This was not the case during the first year of SPP's market, and SPP took steps that largely corrected the incentive issues. SPP proposed changes to the method for distributing over-

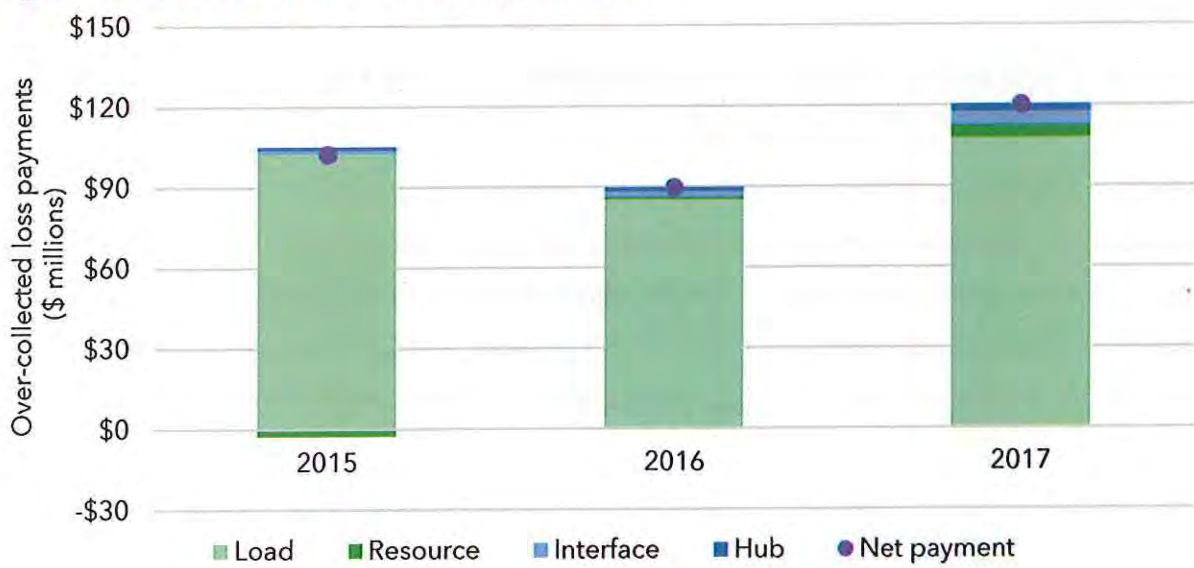
[84] Real-time congestion for load-serving entities and other entities totaled $77.8 million, which is equal to the total real-time congestion uplift. However, real-time congestion uplift is not allocated in the same proportion in which it is collected.

collected losses in FERC Docket No. ER15-763.[85] The Commission accepted these changes, which went into effect in April 2015.

The enhanced design consolidates the distributions of day-ahead and over-collected loss rebates into one distribution. Under this design, both day-ahead and real-time over-collected loss rebates are distributed on just real-time withdrawing megawatts. This includes loads, substation power, exports, wheel-throughs, pseudo-ties, and bilateral settlement schedules (BSS). The only exception is that both day-ahead and real-time bilateral settlement schedules are entitled to the rebate. In addition to consolidating the distributions to only real-time withdrawing megawatts, changes were made to loss pool allocations. Under the old method, virtual transactions drove up the SPP loss pool allocation of over-collected losses rebates, even though virtual activity was not eligible for rebates. This caused real-time exporters to get a large percentage of the over-collected losses rebates which, during that time, were typically a charge. Virtual transactions are no longer considered in the loss pool distributions. These design enhancements better allocate the over-collected losses to the transactions that contributed to the over-collection while removing some of the adverse incentives present under the former design.

Over-collected losses for the past three years are shown in Figure 5–16.

Figure 5–16 Over-collected losses, real time



[85] https://www.ferc.gov/CalendarFiles/20150331172533-ER15-763-000.pdf

A total of $120 million was paid out in over-collected losses rebates during 2017, with $108 million (90 percent) going to load. This is up from $90 million in over-collected losses rebates paid out in 2016 and $103 million paid in 2015.

The use of bilateral settlement schedules changes the distribution of over-collected losses. The bilateral settlement schedules enable market participants to transfer energy from one entity to another at a particular settlement location. It creates a financial withdrawal at the settlement location for the seller and a financial injection at the settlement location for the buyer. As long as the bilateral settlement schedules do not change the net withdrawal at the location, the charges and credits for losses simply change hands between the entities owning the bilateral settlement schedules. Where the bilateral settlement schedules create a net withdrawal that would not otherwise exist, it creates credits and charges that would not otherwise exist. For example, if a bilateral settlement schedule amount at a resource settlement location exceeds the cleared output of the resource, it creates a net withdrawal, and the generation owner receives a loss distribution credit for the excess megawatts of the bilateral settlement schedule. The same occurs with a bilateral settlement schedule at hubs, where no energy is withdrawn, other than a bilateral settlement schedule. The majority of the $4.9 million in distributions at resource settlement locations during 2017 occurred for this reason, as well as $2.6 million at hubs. These distributions cause concern for the MMU, because they create an incentive to game the market rules using bilateral settlement schedules. Exploitation of this aspect of the loss distribution calculation can potentially be market manipulation.

Over-collected losses no longer create charges in the real-time market. Total loss revenues are calculated from both the day-ahead market and the real-time market. SPP distributes them based on real-time market withdrawals only. Virtual transactions no longer factor into the loss pool calculation, reducing the exaggeration of distributions at interfaces and hubs. However, incentives for transacting bilateral settlement schedules in hours with high percentages paid to the SPP loss pool still exist. Additionally, as stated above, bilateral settlement schedules do not contribute to the over-collection of losses, but they are entitled to rebates. Any scenario where a bilateral settlement schedule creates a net withdrawal that would not have existed had the bilateral settlement schedule not been placed creates an opportunity for an over-collected losses rebate. When this happens, the over-collected losses rebate is diluting other rebates that contributed to the over-collection of losses.

A recommendation in the 2014 Annual State of the Market report was to remove bilateral settlement schedule transactions from the over-collected losses distribution calculation. The SPP Market Working Group approved revision request 200[86] in January 2017. This should alleviate the adverse incentives given to bilateral settlement schedules to transact in amounts that vary from the underlying flows of the transaction. The changes are still pending FERC approval, but are expected to be in effect before the end of 2018, if approved.[87]

5.2 TRANSMISSION CONGESTION RIGHTS MARKET

In the Integrated Marketplace, the market generally charges load a higher price than it pays generation. Transmission services are the underpinning of the transmission congestion rights market, which provides day-ahead market payments to hedge the cost of congestion. Annual and monthly transmission congestion right auctions award the "rights" to shares of day-ahead market congestion revenue. SPP allocates auction revenue rights in annual and monthly processes based on transmission ownership. Auction revenue right holders receive payments from the auction revenue that offset the cost of transmission congestion right purchases, and conversions of auction revenue rights into transmission congestion rights.[88]

The purpose of the transmission congestion right market is to provide a market mechanism for SPP load-serving entities to hedge the cost of congestion in the market. It can also be used as a mechanism for speculation and hedging by load-serving entities, generators, and financial entities. The performance of the transmission congestion right market is expressed by the degree to which transmission congestion rights and auction revenue rights provide a congestion hedge to load customers. The degree to which day-ahead market congestion revenues sufficiently fund the transmission congestion rights serves as a measure of load hedging, market efficiency, and transparency.

[86] RR 200 (Design change for bilateral settlement schedule and over-collected losses distribution)
[87] ER18-792-000
https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14815024
[88] Further details about the payment structure of the transmission congestion rights market can be found in the 2016 Annual State of the Market Report, pp. 125-126.

5.2.1 MARKET TRANSPARENCY AND EFFICIENCY

5.2.1.1 Hedging the day-ahead market

The transmission congestion right and auction revenue right net payments paid to entities in the SPP market are shown in Figure 5–17.

Figure 5–17 Total congestion payments [89]

(in $ millions)	Load-serving entities			Non-load-serving and financial only entities		
	2015	2016	2017	2015	2016	2017
DA congestion	$ (148.6)	$ (259.6)	$ (364.6)	$ (31.5)	$ (81.2)	$ (219.0)
RT congestion	(3.4)	(20.4)	(48.3)	40.1	63.7	126.1
Net congestion	(152.0)	(280.0)	(412.9)	8.6	(17.5)	(92.9)
TCR charges	(148.2)	(51.0)	(122.5)	(76.4)	(63.5)	(138.0)
TCR payments	126.7	212.4	308.8	83.3	158.7	314.3
TCR uplift	(18.3)	(21.0)	(24.3)	(15.2)	(18.0)	(31.8)
TCR surplus *	2.2	4.2	4.5	1.4	4.1	5.9
ARR payments	175.6	74.8	147.2	(15.8)	6.5	11.7
ARR surplus	30.6	24.0	94.2	3.4	3.1	7.0
Net TCR/ARR	168.5	243.3	407.9	19.2	90.8	169.1

* remaining at year end

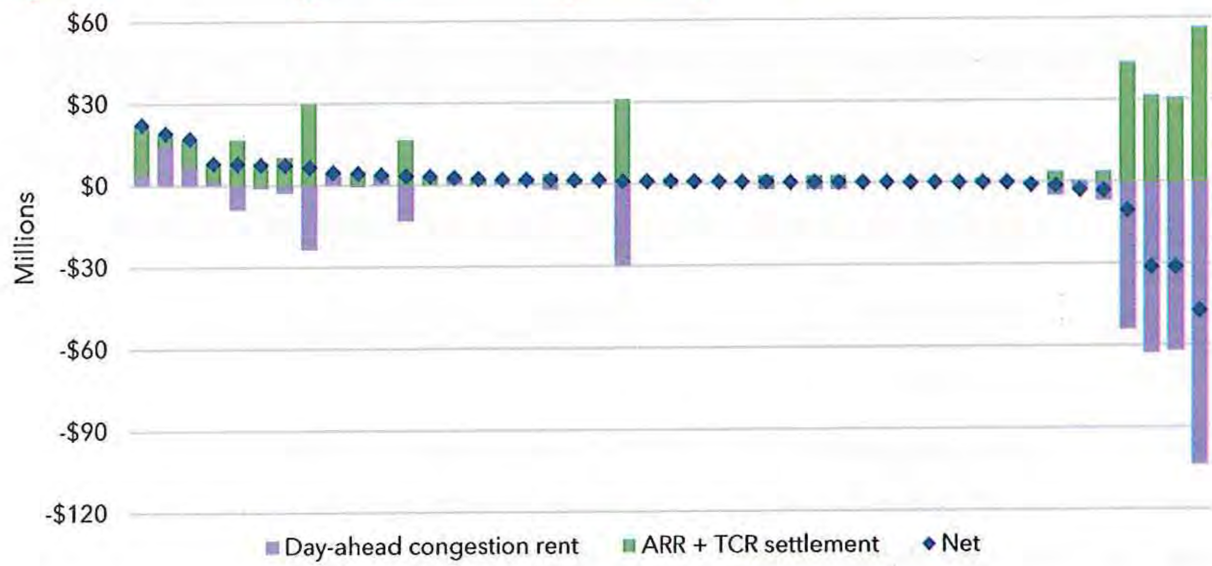
Payments to load-serving entities of $408 million was greater than their day-ahead congestion costs of $365 million for 2017. However, the total of day-ahead and real-time congestion costs were slightly higher at $413 million. This shows that overall, load-serving entities did a good job at hedging congestion through the transmission congestion right market. In aggregate for 2017, non-load-serving and financial only entities collected transmission congestion right and auction revenue right net revenues of $169 million, which exceeded their day-ahead and real-time market congestions costs of $93 million. As mentioned in previous sections and shown in the chart, day-ahead congestion costs have had major increases with a 75 percent increase between 2015 and 2016, and another 40 percent increase in 2017.

[89] Transmission congestion right charges and auction revenue right payments are less in 2016 and 2017 because of the long-term transmission congestion right design. Long-term transmission congestion rights get converted directly to transmission congestion rights, and therefore, are not accessed auction revenue right payments or transmission congestion right charges.

5.2.1.2 Bidding behaviors

A key topic that was discussed in the stakeholder process in 2017 was related to being able to get auction revenue rights to adequately hedge positions. As noted above, in aggregate, load-serving entities received more revenue from their auction revenue rights and transmission congestion rights then they had to pay in day-ahead congestion costs. However, on the individual participant level, some load-serving entities were under-hedged while others were over-hedged. Figure 5–18 shows, by load-serving entity, the day-ahead congestion exposure along with the value of auction revenue right and transmission congestion hedges as well as the net overall position.

Figure 5–18 Net congestion revenue by market participant



The figure highlights that the majority of participants received positive net revenues, while a handful of participants had hedges that significantly did not cover their day-ahead congestion costs. For instance, the bottom three participants paid over $30 million more in congestion costs than was hedged by their auction revenue right and transmission congestion right positions.

Some market participants expressed concern that there were market design issues that were keeping them from getting the appropriate auction revenue rights, which would ultimately be converted into transmission congestion rights to provide a hedge. The main issue discussed was the use of counter-flow in the allocation. In the auction revenue right allocation, counter-flow paths are usually seen as charges and market participants are not required to nominate them. Market participants may make the financial decision to not nominate these counter-flow paths; however, that decision has risks associated with it. If the day-ahead congestion patterns change to where the path is no longer a counter-flow, then the market participant is completely exposed to any congestion. This scenario was observed in 2017. There were many paths that were considered counter-flow paths in 2016 and were not nominated in 2017 by some participants. However, many of these counter-flow paths became prevailing flow, which left the paths unhedged.

Some market participants lost out on valuable hedging mechanisms by choosing not to nominate certain candidate auction revenue rights, which included both prevailing flow and counter-flow paths. Each market participant gets to choose the level of risk it is willing to take by how it nominates its candidate auction revenue rights. Nominating to match the day-ahead position, whether the path is counter-flow or prevailing flow, can lead to lower risk. However, this could also potentially lower the hedge value revenue. At this point, the MMU believes that part of the issue with the lack of allocated auction revenue rights appears to be related to bidding strategy.

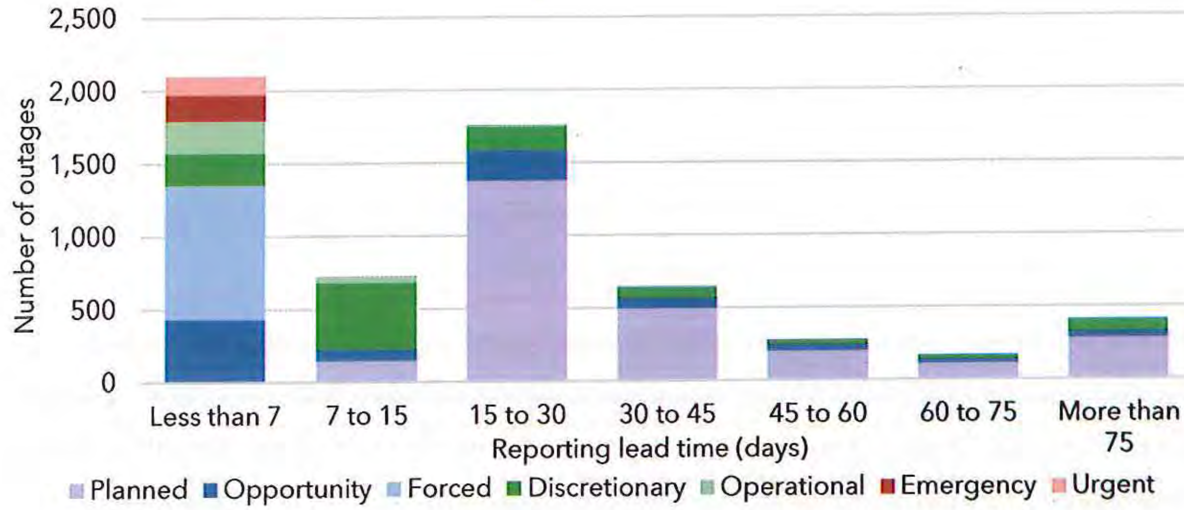
Transmission service reservations are studied and granted with assumptions that include counter-flow megawatts. This means that without the use of counter-flow, many of the prevailing flow paths are not feasible. Nominating the appropriate counter-flow paths in the allocation will help to increase the amount of prevailing flow paths allocated. This ultimately means the less counter-flow nominated will result in less prevailing flow allocated, which could further limit the available transmission congestion hedges.

The difference in prevailing flow and counter-flow can be the result of transmission upgrades, but could also be the result of unmodeled outages. This disconnect between outages modeled in the day-ahead market and the transmission congestion right process is outlined below.

5.2.1.3 Transmission outage modeling

When outages appear in the day-ahead market that were not in the transmission congestion rights market, they reduce system capacity and likely cause underfunding. Figure 5–19 shows transmission outages by the reported lead time.

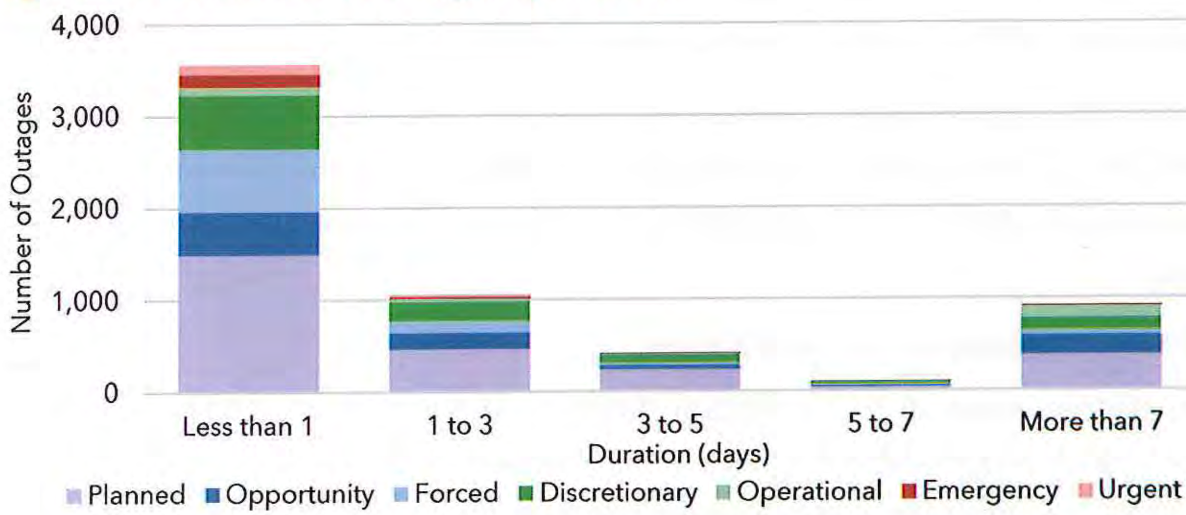
Figure 5–19 Transmission outages by reporting lead time



SPP models only transmission outages that were reported at least 45 days prior to the first of the month in the transmission congestion rights auction.[90] However, SPP only requires transmission owners to submit planned outages 14 days in advance.[91] The above figure shows that the majority of outages are not considered in the transmission congestion rights markets solely due to the submission lead time. Roughly 86 percent of outages are ruled out of the transmission congestion right model by this phase alone.

Figure 5–20 shows the duration in days for the different types of outages.

Figure 5–20 Transmission outages by duration

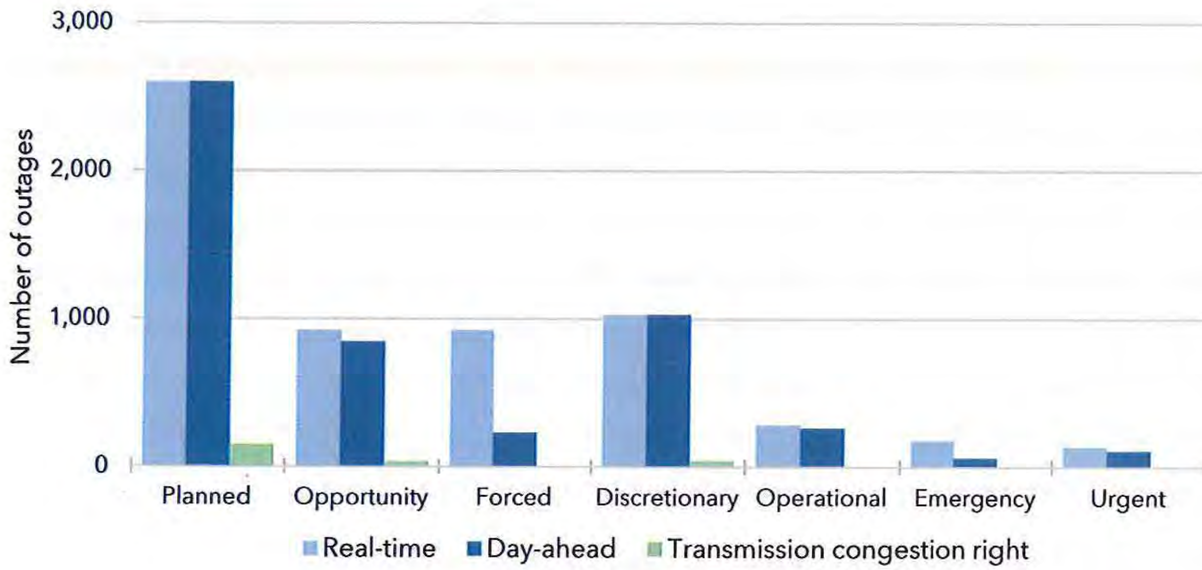


[90] SPP Integrated Marketplace Protocols, Section 6.6
[91] SPP Operating Criteria Appendix OP-2

Outages shorter than five days are excluded from auction revenue right/transmission congestion right processes. This means the vast majority of outages (83 percent) are excluded from the transmission congestion rights models because they are less than five days.

Figure 5–21 shows outages by real-time, day-ahead, and transmission congestion right markets.

Figure 5–21 Transmission outages by market



While the number of outages in the day-ahead and real time are similar, the outages represented in the transmission congestion rights market are only a fraction of the total number of outages. The transmission congestion market only includes outages that are longer than five days, and are submitted at least 45 days in advance of the first of the month. This represented only four percent of total outages in the day-ahead market. These differences in outages can create underfunding of transmission congestion rights.

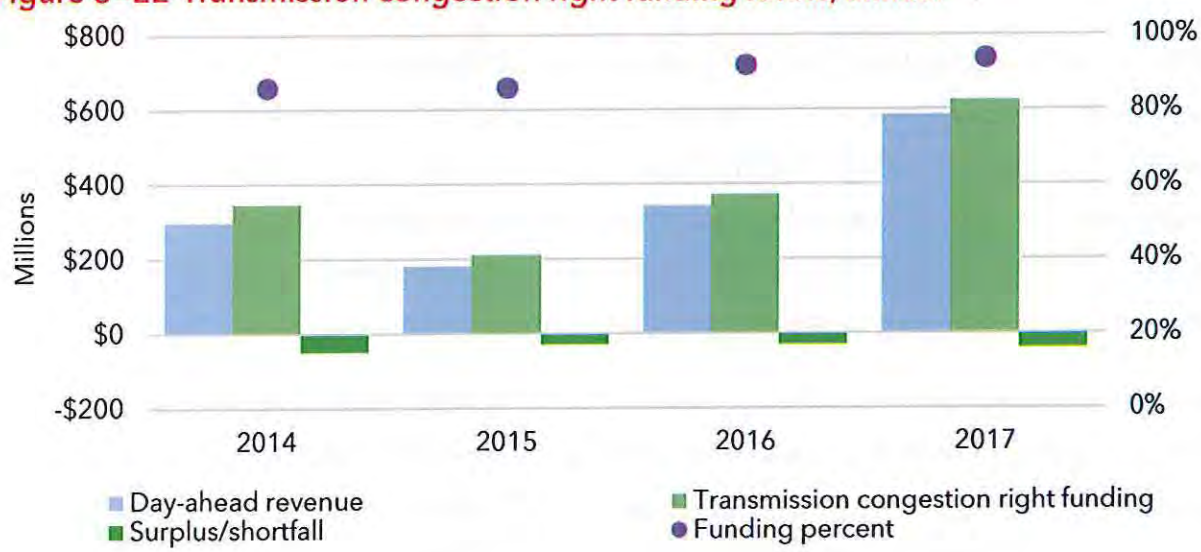
Ideally, outages in the transmission congestion rights markets would be perfectly aligned with the day-ahead market. However, the MMU understands the challenges associated with accounting for outages in the transmission congestion rights market and recognizes that there can never be an exact match among the markets. Even so, improving how outages are handled and accounted for in the auction processes could help to improve underfunding. We encourage stakeholders to consider both counter-flow positions and outages in determining how to improve the funding issues identified by stakeholders in 2017.

5.2.2 FUNDING

Overall funding for transmission congestion rights (94 percent) and auction revenue rights (164 percent) improved in 2017 relative to previous years. This is likely related to changes implemented based on concerns identified in previous years. However, overfunding of auction revenue rights signals a different set of concerns. In particular, we continue to encourage SPP to review and address the reasons for this overfunding.

In the 2014 and 2015 Annual State of the Market reports, the MMU discussed a recommendation and corresponding revision request[92] that was intended to reduce over-allocation of auction revenue rights and the resultant over-selling of transmission congestion rights by reducing the transmission capability in the annual auction revenue right allocation. This revision request made its way through the SPP stakeholder process in 2015 and 2016, in which a final approval was made by FERC in time for the 2016 annual auction revenue right/transmission congestion right processes. The "TCR year" runs from June 1 through May 31 of each year, so it is not in-sync with our annual report year. Looking at a calendar year of data, 2014 and 2015 did not include these revisions, 2016 included the revisions for half the year, and 2017 included the revisions for the entire year. The effects from the revisions can be seen with the annual funding percentage increases in Figure 5–22.

Figure 5–22 Transmission congestion right funding levels, annual

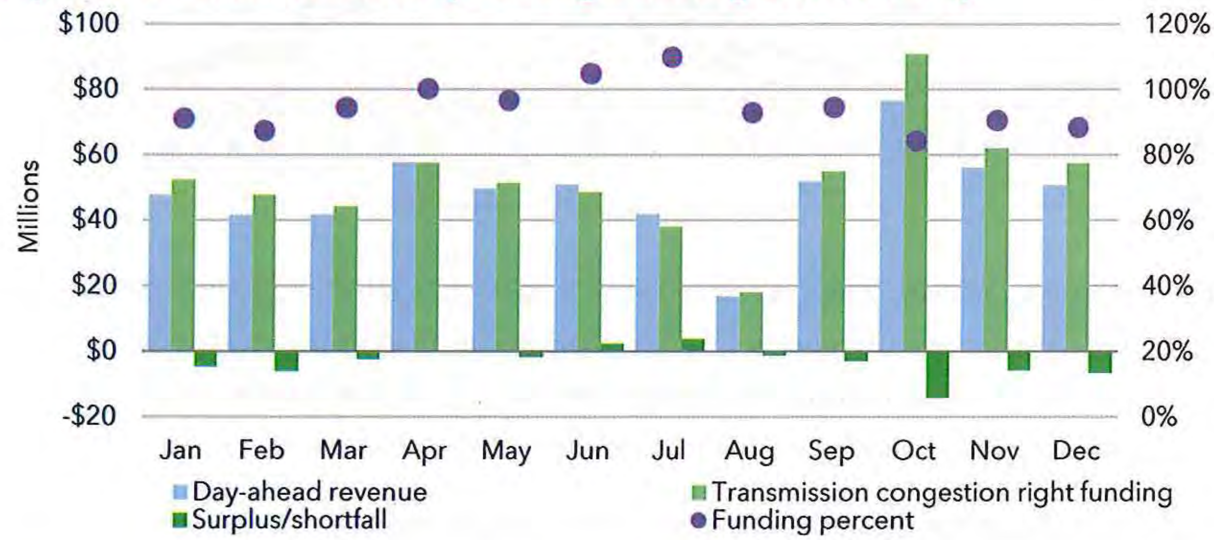


[92] Revision request 91

The 2015 calendar year, which did not include the revisions, showed 86 percent net transmission congestion right funding. The 2016 calendar year, in which about half the year included the revisions, showed 92 percent net transmission congestion right funding. The 2017 calendar year, which included the revisions for the entire year, showed 94 percent net transmission congestion right funding.

Monthly transmission congestion right fund levels and revenue are shown in Figure 5–23.

Figure 5–23 Transmission congestion right funding levels, monthly

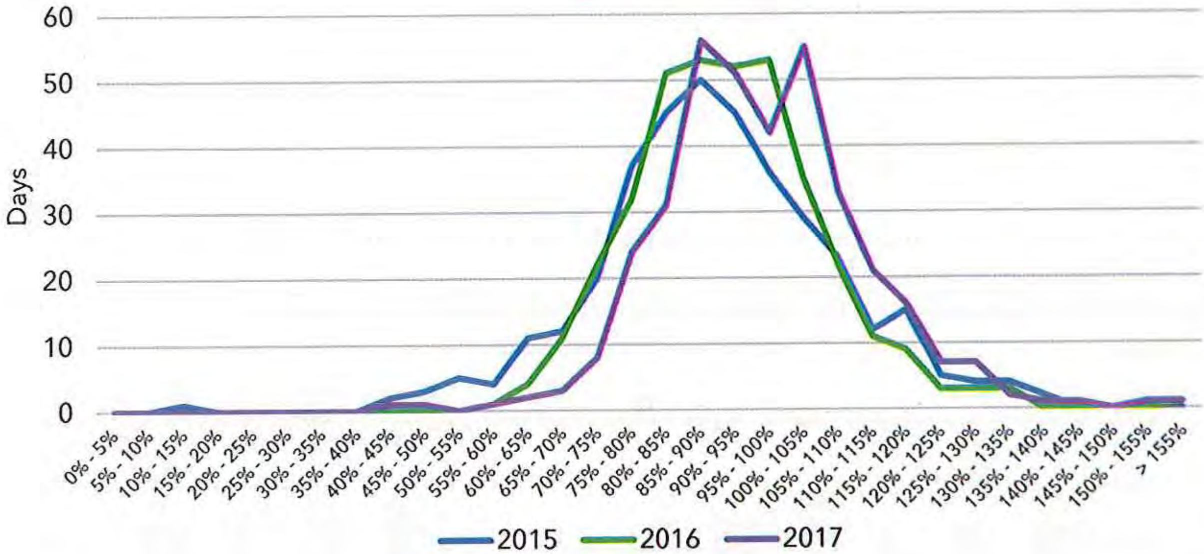


The monthly averages appear fairly consistent, with the majority of the months staying within the 90 to 100 percent target range.[93] While the percent of funding was improved in 2017 by the implementation of revision request 91, higher congestion costs actually increased the amount of underfunding compared to the previous years. The trend of over-selling transmission congestion rights appears to continue, but was reduced by revision request 91.

Daily observations of transmission congestion right funding for the past three years are shown in Figure 5–24.

[93] Target range is specified in the Protocols section 5.3.3. "In the event the cumulative funding is at or below 90% or above 100%, MWG may approve an additional adjustment..."

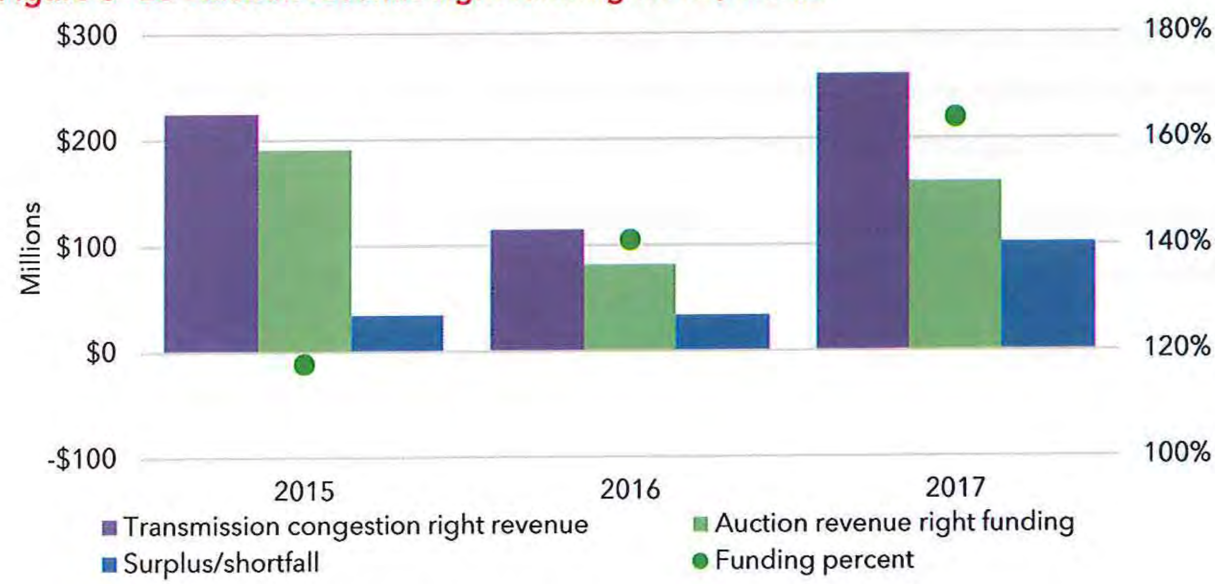
Figure 5–24 Transmission congestion right funding, daily



Most daily observations of transmission congestion right funding falls between 80 percent and 100 percent, as seen in Figure 5–24. While variation in funding can be expected as a result of factors including transmission outages and derates, the fact that the majority of funding falls in this range indicates that the overall process is generally effective.

Figure 5–25 shows that the auction revenue right funding percentage has increased over the last several years as revision request 91 was implemented.

Figure 5–25 Auction revenue right funding levels, annual



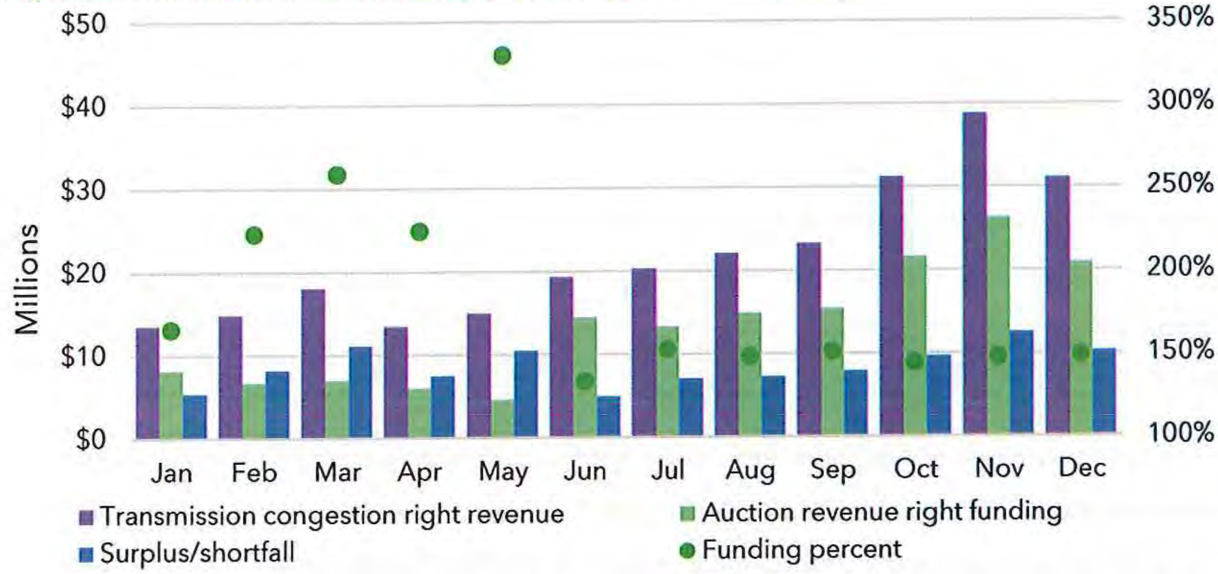
This is likely a result of the decreased amount of auction revenue right megawatts available as a result of reduced transmission capability in the annual allocation. This reduction of auction revenue rights was a known and expected outcome of the design change. Even though there are fewer overall auction revenue rights, the new design better aligns auction revenue rights and transmission congestion rights and allows for better feasibility of auction revenue rights. The increase in auction revenue right funding was not expected from the revision request, and may not be related to the change. This high amount of auction revenue right surplus still presents a potential concern that was identified in last year's State of the Market report.

In 2015, transmission congestion rights were approximately 86 percent funded by the day-ahead market while auction revenue rights were 118 percent funded. In 2016, transmission congestion rights were approximately 92 percent funded by the day-ahead market while auction revenue rights were 141 percent funded. From 2016 to 2017, day-ahead market revenues and transmission congestion right payments rose again because of congestion caused by increased wind generation. In 2017, transmission congestion rights were approximately 94 percent funded by the day-ahead market while auction revenue rights were 164 percent funded.

Interestingly, transmission congestion right annual shortfalls increased by 44 percent from $39 million in 2016 to $56 million in 2017. However, auction revenue right surpluses saw a drastic increase this year from $27 million in 2016 to $101 million in 2017.

Figure 5–26 shows the 2017 monthly funding levels and revenues for auction revenue rights.

Figure 5–26 Auction revenue right funding levels, monthly



The large shift in auction revenue rights in funding in June reflected the change in the TCR year. The figure also shows the auction revenue right funding drastically increasing from 230 percent funding in April to 330 percent funding in May.

5.2.3 MODELING CONCERNS

The MMU has reported on several transmission congestion right modeling issues in its previous annual reports, one of which still presents a cause for concern.

5.2.3.1 Auction revenue right funding

As previously noted, the auction revenue right funding levels are higher than expected. Auction revenue right surplus in conjunction with transmission congestion right underfunding tend to point to an overselling of transmission congestion rights. More revenues are collected from the purchases of transmission congestion rights than are needed to fund the auction revenue rights. Transmission congestion right owners may have paid too much for their transmission congestion rights, but instead of receiving a refund, the over-payment was allocated to the auction revenue right holders.

This extreme amount of surplus causes a concern for a few reasons. First, the entities that make up the pool of transmission congestion right holders are not the same entities that make up the pool of auction revenue right holders. Auction revenue right holders are only those entities with long-term firm transmission service. Second, the allocation of over collections is not related to over-payment. For instance, the over-payment of transmission congestion rights could primarily come from a small constrained area, but the allocation goes back to auction revenue right holders in a method similar to the load ratio share and has nothing to do with where the excess funds came from.

The MMU urges SPP, along with the stakeholders, to review the causes of overfunding, develop a plan to get auction revenue right funding closer to the 100 percent funding level, and analyze the distribution of surplus to ensure it is performed in an equitable manner. We suggest that this be addressed going forward.

6 COMPETITIVE ASSESSMENT

The SPP Integrated Marketplace provides sufficient market incentives to produce competitive market outcomes in regions and periods when there are no concerns with regard to local market power. The MMU's competitive assessment provides evidence that in 2017 market outcomes were workably competitive and that the market required mitigation of local market power infrequently to achieve those outcomes.

The market power analysis in this report considers both the structural and behavioral aspects of market power concerns. The structural aspects can be detected by various techniques such as market share analysis, (market-wide) concentration indices, and pivotal supplier analysis. The structural indicators are used to look for the potential for market power without regard to the actual exercise of market power. Behavioral aspects, on the other hand, assess the actual offer or bid behavior (i.e., conduct) of the market participants, and the impact of such behavior on market prices by looking for the exercise of market power. These behavioral indicators include offer price markup[94] (Section 6.2.1); economic withholding analysis, addressed through automated mitigation (Section 6.2.2); output gap analysis (Section 6.2.3); and physical withholding (Section 6.2.4).[95]

This chapter evaluates the SPP market's competitive environment first by establishing the level of structural market power and then examining market prices for indications of market power impact. The level of structural marker power is assessed both at the general level through concentration indices and at the local–transmission constraint–level through pivotal supplier analysis. Mitigation of economic withholding is accomplished *ex-ante* through automatic market power mitigation processes that limit the ability of generators with local market power to raise prices above competitive levels. The mitigation program is monitored and evaluated to ensure it is efficient and effective. Accordingly, the following subsections examine the significance of market power and the effectiveness of local market power mitigation in the SPP markets.

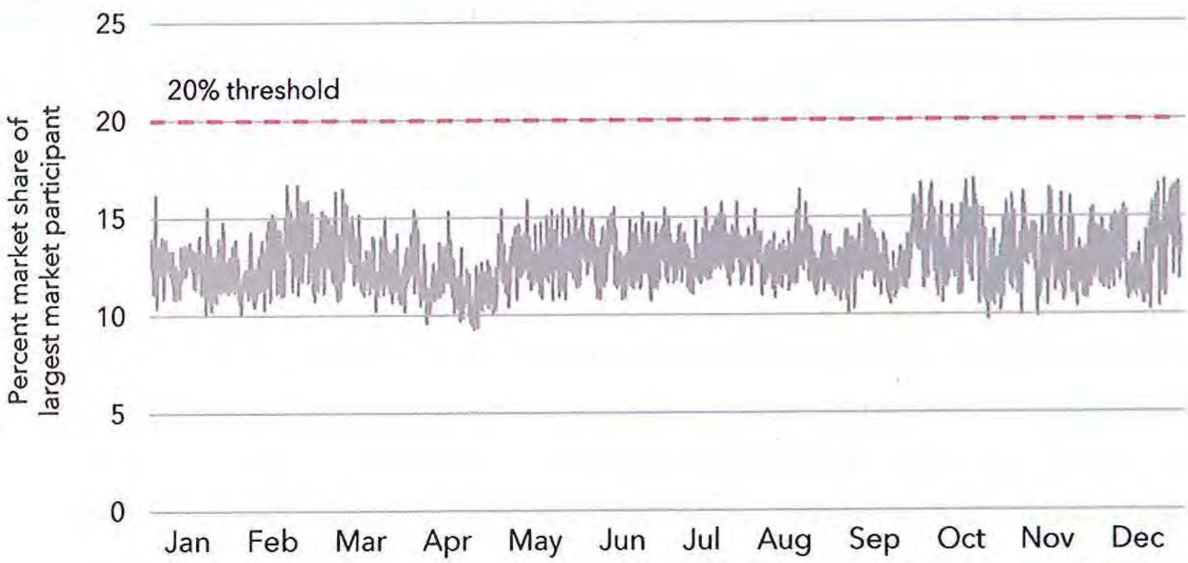
[94] While the SPP MMU uses offer price markup, other market monitors may use price cost markup as a behavioral indicator.
[95] The uneconomic production analysis, as another behavioral indicator, is addressed through FERC referrals.

6.1 STRUCTURAL ASPECTS OF THE MARKET

Three core metrics of structural market power are the market share analysis, the Herfindahl-Hirschman Index (HHI), and pivotal supplier analysis. The first two of these indicators measure concentration in the market and are of a static nature. Pivotal supplier analysis, on the other hand, takes into account the dynamic nature of power markets and considers changing demand conditions and locational transmission constraints in assessing potential market power.

Figure 6–1 displays the market share of the largest on-line supplier (i.e., market participant) in terms of energy output in the real-time market by hour for 2017.

Figure 6–1 Market share of largest supplier



The market share ranged from 9.3 percent to 16.9 percent, never exceeding the 20 percent threshold[96] in any of the hours for the year. This was down slightly from a range of 9.6 percent to 19.7 percent in 2016. The majority of the highest market share hours occurred during the shoulder months of the year.

[96] The 20 percent threshold is one of the generally accepted metrics that would indicate structural market power. Note, however, that neither market share nor the HHI metric alone would be sufficient for the assessment of market power particularly in today's spot electricity markets where load pockets formed by transmission congestion may lead to market power with much smaller market shares and/or HHI values.

The HHI is another general measure of structural market power, analyzing overall supplier concentration in the market. It is calculated by using the sum of the squares of the market shares of all suppliers in a market as follows:

$$HHI = \sum_i \left(\frac{MW_i}{\sum_i MW_i} * 100\right)^2$$

According to FERC's "Merger Policy Statement,"[97] which is similar to Department of Justice merger guidelines, an HHI less than 1,000 is an indication of an unconcentrated market, an HHI of 1,000 to 1,800 indicates a moderately concentrated market, and an HHI over 1,800 indicates a highly concentrated market.

Figure 6–2 provides the number of hours for each concentration category over the last three years.

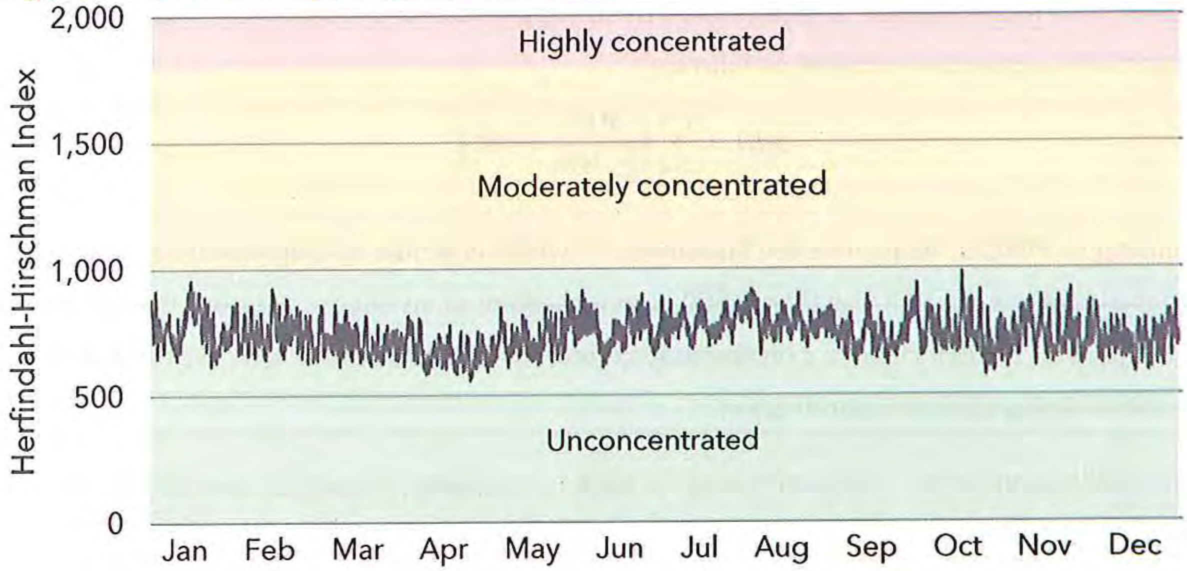
Figure 6–2 Market concentration level, real time

Concentration	HHI Level	2015		2016		2017	
		Hours	% of Hours	Hours	% of Hours	Hours	% of Hours
Unconcentrated	Below 1,000	6,234	71%	8,784	100%	8,760	100%
Moderately Concentrated	1,000 to 1,800	2,526	29%	0	0%	0	0%
Highly Concentrated	Above 1,800	0	0	0	0%	0	0%

In terms of installed capacity, the SPP market was unconcentrated 100 percent of the hours in 2016 and 2017. The HHI in the SPP market has never risen above the highly concentrated threshold of 1,800 since the Integrated System joined SPP in October 2015. Figure 6–3 depicts the hourly real-time market HHI in terms of generation for 2017.

[97] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, Issued December 18, 1996 (Docket No. RM96-6-000).

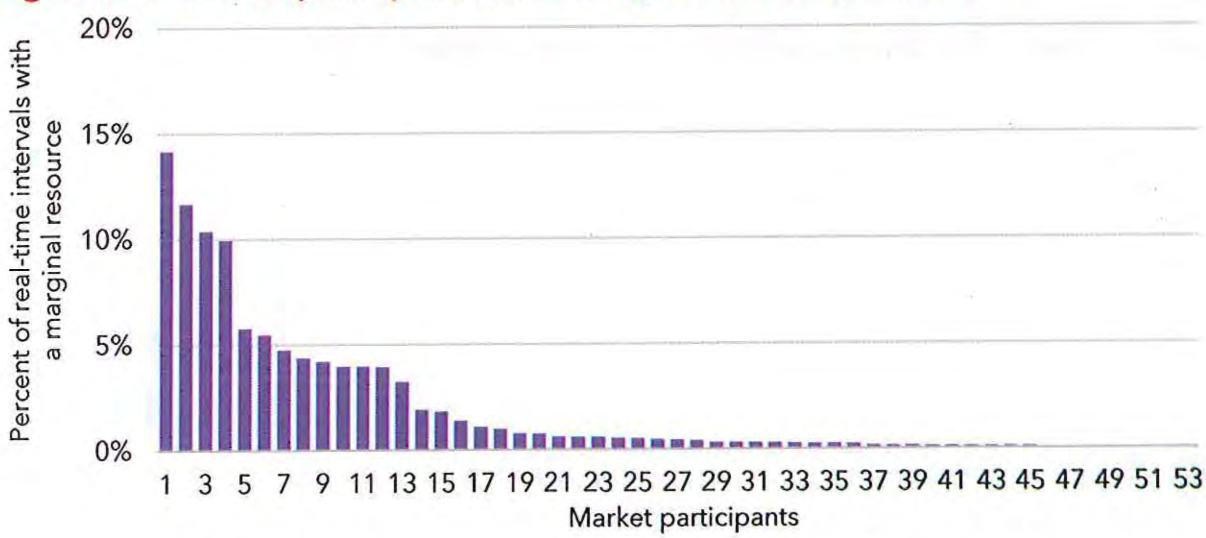
Figure 6–3 Herfindahl-Hirschman Index



Hourly HHI values ranged from 558 to 986 during 2017, which were very similar to the range of values in 2016.

SPP market participants with generation spanning all supply segments,[98] reflecting the technology and fuel mix of resources, have the greatest ability to benefit from structural market power. These market participants may frequently set prices regardless of the technology type on the margin. Figure 6–4 provides the percent of real-time market intervals that each market participant had a resource on the margin.

Figure 6–4 Market participants with a marginal resource, real time



[98] Supply segments include base, intermediate, and peak resources.

The chart shows that the top three market participants each set price in more than 10 percent, but less than 15 percent, of all real-time market time intervals. Conversely, well over half of all participants set price in less than one percent of all intervals.[99]

The MMU's market share analysis and calculated HHI both indicate minimal potential for general structural market power in SPP markets outside of areas that are frequently congested. Structural market power is also assessed at a more localized level and in the context of locational transmission constraints by reevaluating frequently constrained areas periodically and (re)defining them accordingly as was discussed in Section 5.1.7.

Pivotal supplier analysis takes into account the dynamic nature of the power market, particularly demand conditions, and evaluates the potential for market power in the presence of "pivotal" suppliers. A supplier is pivotal when its resources are needed to meet demand. There may be one or more pivotal suppliers in a particular market defined by transmission constraints and load conditions, and a supplier's status of being pivotal may vary between time periods irrespective of its size. In the market clearing process, market power is evaluated locally through a local market power evaluation because the exercise of local market power is relevant for determining prices.

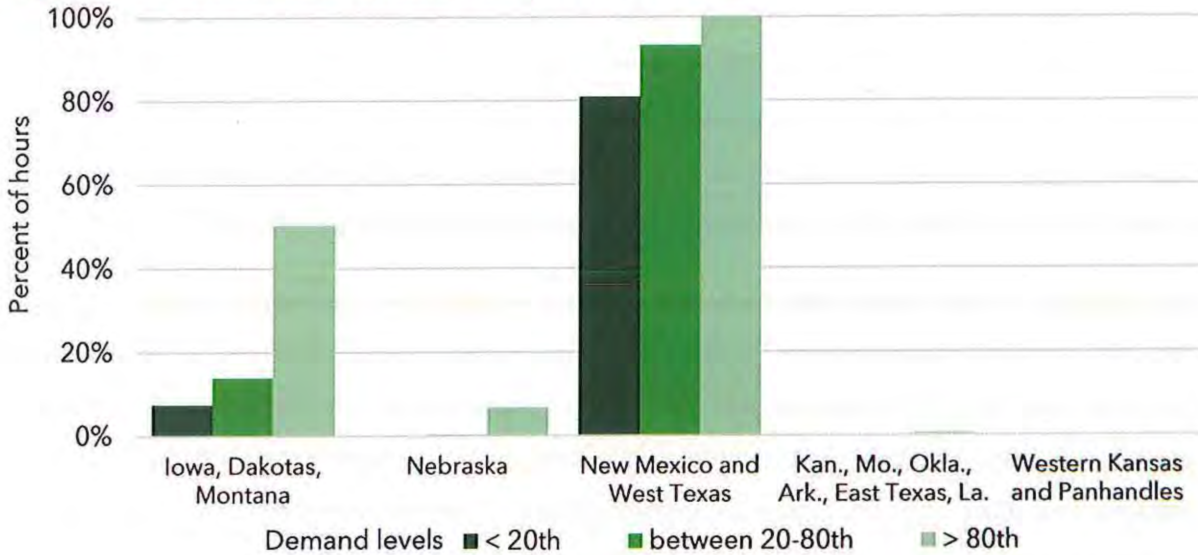
The following analysis identifies the frequency with which at least one supplier was pivotal in the five different reserve zones (regions) of the SPP footprint in 2017.[100] One condition for a supplier to have an ability to raise prices above competitive levels, is the frequency it becomes pivotal. Another market condition is during times of shortage or high demand. The mere size of a supplier has no link to being pivotal; however, suppliers with a high frequency of being pivotal in tight supply periods have an even greater ability to exercise market power. For this reason, the frequency of being a pivotal supplier is also analyzed at various levels of demand across these five regions.

[99] The percentages on this chart are not additive because multiple market participants may have a resource on the margin during any given interval.

[100] SPP divides market resources (generation) into five reserve zones. For the purpose of this report, these reserve zones are named as "Nebraska", "Western Kansas and Panhandles", "New Mexico and West Texas", "Kan., Mo., Okla., Ark., East Texas, La.", and "Iowa, Dakotas, Montana". Thus, each generation resource is mapped to one of these reserve zones. To define a load zone to match with a resource zone, each load settlement location was mapped to a reserve zone to approximate demand within a particular zone. Additionally, import limits are approximated by the average of the reserve zone limits for the times they were activated in 2017.

Figure 6–5 shows how frequently a supplier is pivotal at varying load levels in the five reserve zones in the SPP market footprint.

Figure 6–5 Hours with at least one pivotal supplier



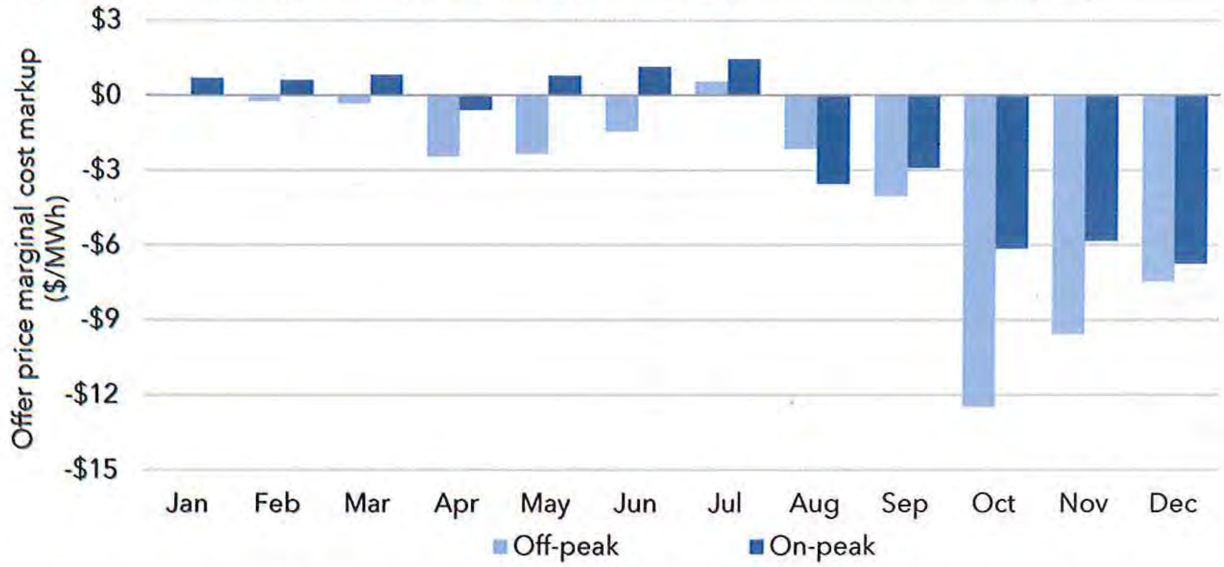
The results indicate that the percent of hours with pivotal supplier is the highest (81 to 100 percent) in the New Mexico and West Texas region, increasing with demand level. This is where one of the SPP's frequently constrained areas in 2017 was located. This region is followed by the Iowa, Dakotas, Montana region where, depending on the level of load, seven to 50 percent of the hours exhibit at least one pivotal supplier. The remaining regions experience pivotal supplier conditions for only negligible periods, and only at the higher load levels.

6.2 BEHAVIORAL ASPECTS OF THE MARKET

6.2.1 OFFER PRICE MARKUP

In a competitive market, prices should reflect the short-run marginal cost of production of the marginal unit. In SPP's Integrated Marketplace, market participants submit hourly mitigated energy offer curves that represent their short-run marginal cost of energy. Market participants also submit their market-based offers, which may differ from their mitigated offers. To assess market performance, a comparison is made between the market offer and the mitigated offer for the marginal resources for each real-time market interval. Figure 6–6 provides the average marginal resource offer price markups[101] by month for on-peak and off-peak periods.

Figure 6–6 Average offer price markup of marginal resource, monthly

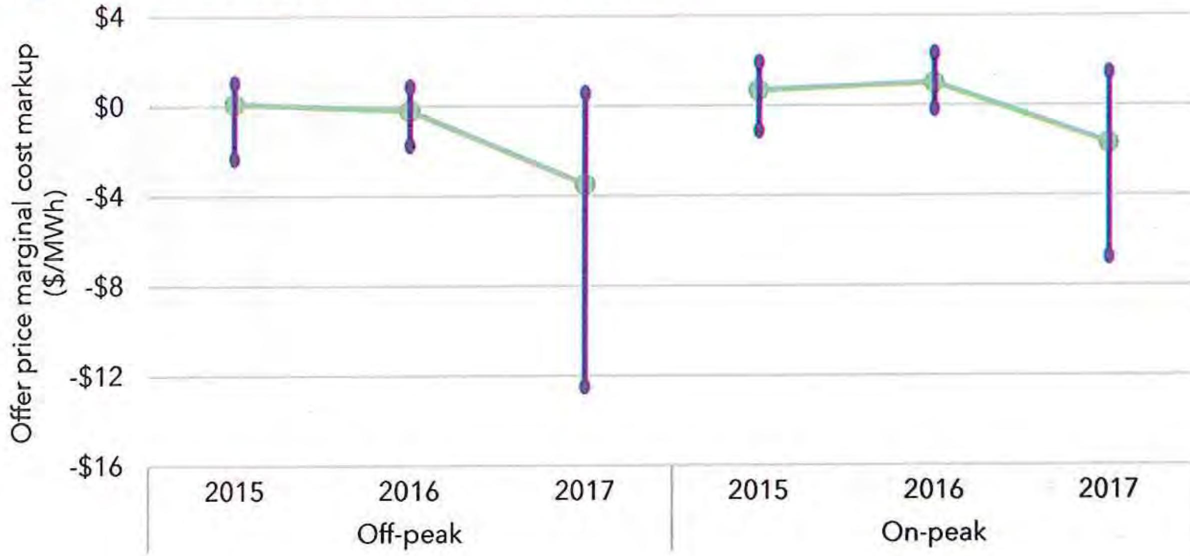


In 2017 the average monthly markups ranged from -$12.48 to $0.56/MWh for off-peak periods and from -$6.75 to $1.44/MWh for on-peak periods. The lowest markups occurred in fall and winter in off-peak hours, when wind generation was generally the highest. During six months the average on-peak markup was also negative at relatively high magnitudes. The negative markups in 2017 were significantly higher compared to 2016 (see Figure 6–7 for annual ranges). The observed levels of negative markups indicate that some market participants' real-time market offers were below their mitigated offers. This could occur where generators decide to offer below their marginal cost to maintain commitments in a very competitive marketplace. Coal plant operators may have a negative opportunity cost resulting from an oversupply of coal or possible exposure to a take-or-pay contract. Negative markups could also occur when wind units become marginal and their (negative) offers clear the market.[102] For instance, wind resources at the margin increased from 7.9 percent of all

[101] Offer price markup is calculated as the difference between market-based offer and the mitigated offer where the market-based offer may or may not be equal to the mitigated offer. The MMU calculates a simple average over all marginal resources for an interval. The markups are not weighted to reflect each marginal resource's proportional impact on the price.
[102] Wind units may have negative mitigated offers because of subsidies related to production tax credits.

resource hours in 2016 to 10.4 percent in 2017, indicating a 31 percent increase. Figure 6–7 below points to a declining annual trend of off-peak and on-peak average markups.

Figure 6–7 Average offer price markup, annual



Both off-peak and on-peak average markups were at the lowest levels since implementation of the Integrated Marketplace at around -$3.50/MWh and -$1.70/MWh, respectively. Although a lower offer price markup level in itself would indicate a competitive pressure on suppliers in the SPP market, the observed continuous downward trend may raise questions about the commercial viability of generating units and the possibility of generation retirements.

6.2.2 MITIGATION PERFORMANCE AND FREQUENCY

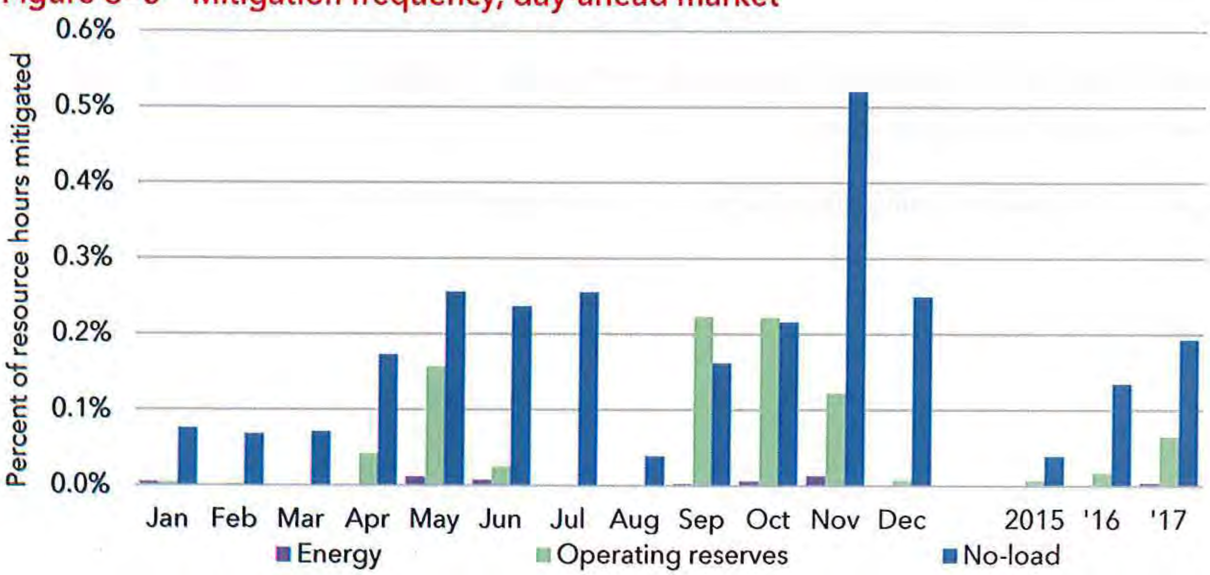
SPP employs an automated conduct and impact mitigation scheme to address potential market power abuse through economic withholding. The mitigation applies to resources that exercise local market power in areas of transmission congestion, reserve zone shortages, and manual commitments in instances where there is the potential for manipulation due to a manual commitment that guarantees recovery of a resource's submitted market offers.

SPP resources' incremental energy, start-up, no-load, and operating reserve offers are subject to mitigation for economic withholding when the following three circumstances occur simultaneously in a market solution:

1) The resource has local market power;
2) The offer has failed the conduct test. Resources submit two offers for each product: a mitigated offer representing the competitive baseline costs that must adhere to the mitigated offer development guidelines[103] and a second offer generally referred to as a market offer. An offer fails the conduct test when the market offer exceeds the mitigated offer by more than the allowed threshold; and
3) The resource is manually committed by SPP for capacity, transmission constraint, or voltage support; or by a local transmission operator for local transmission problems or voltage support; and the application of mitigation impacts market prices or make-whole payments by more than the allowed $25/MWh threshold.

Mitigation was very low overall, with some variation across products and markets. Figure 6–8 shows that the mitigation of incremental energy, operating reserves, and no-load was generally infrequent in the day-ahead market in 2017.

Figure 6–8 Mitigation frequency, day-ahead market

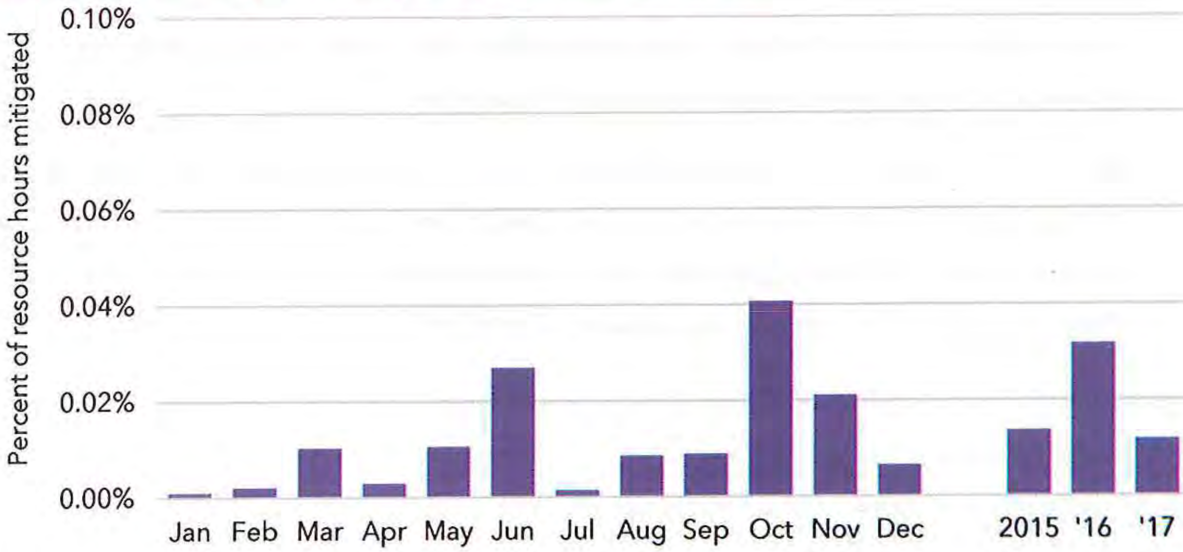


[103] As indicated in Appendix G of the SPP's Market Protocols.

Mitigation frequency in the day-ahead market increased slightly starting in April (with the exception of August), particularly for no-load. The application of mitigation in the day-ahead market occurred at levels of 0.06 percent for operating reserves, 0.19 percent for no-load, less than 0.01 percent for incremental energy, and about three percent of starts.

Mitigation of incremental energy in the real-time market is shown in Figure 6–9 below.

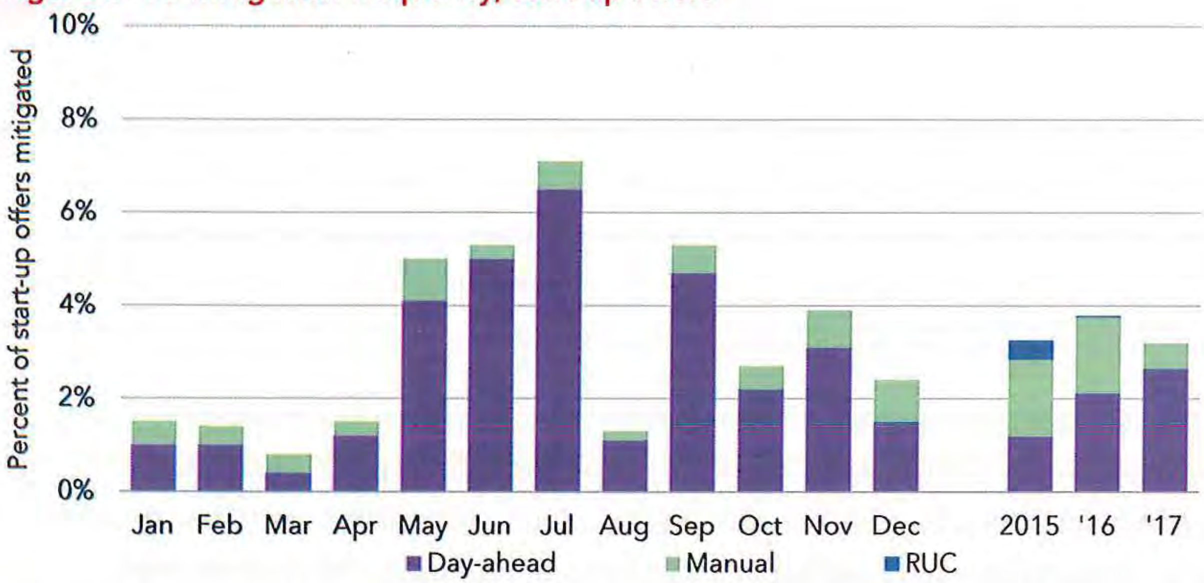
Figure 6–9 Mitigation frequency, real-time market



For the real-time market, the mitigation of incremental energy has been at very low levels since the start of the market with an annual average around 0.01percent in 2017, which is down by a third from 2016 levels.

Figure 6–10 shows the mitigation frequency for start-up offers for the various commitment types.

Figure 6–10 Mitigation frequency, start-up offers



The overall mitigation frequency of start-up offers was the lowest since the market began in 2014, as it decreased in 2017 relative to 2016 levels to just over three percent. While the frequency of manual and real-time mitigation dropped in 2017 compared to 2015 and 2016, day-ahead mitigation increased to 2.7 percent. Day-ahead mitigation accounts for 83 percent of the total start-up cost mitigation. The highest level of mitigation of start-up offers was at seven percent in July and has since fallen to around two percent in December.

6.2.3 OUTPUT GAP (MEASURE FOR POTENTIAL ECONOMIC WITHHOLDING)

Economic withholding by a resource is defined as submitting an offer that is unjustifiably high such that either the resource will not be scheduled or dispatched, or if scheduled or dispatched the offer will set a higher than competitive market clearing price. Accordingly, the output gap metric aims to measure the economic (or competitive) amount of output that was withheld from the market by submitting offers in excess of competitive levels. The output gap is the amount of generation not produced as a result of offers exceeding the mitigated offer above an appropriate conduct threshold. The conduct threshold is employed to compensate for any inaccuracies or uncertainties in estimating the cost, similarly to the one used in economic withholding mitigation. In this report, the output gap is calculated as the difference between the resource's economic level of output at the prevailing market clearing price and the actual amount of production. The economic level of output is produced by a generator between its minimum and maximum economic capacity.[104]

The output gap calculation adopts a new approach this year for calculating economic output.[105] Under this new approach, units were grouped into two categories: economic units that are not committed, and committed units that are dispatched at lower levels than their economic level. Accordingly, we implemented a multi-stage process to determine the economic output level for a unit for output gap evaluation.

In the first stage, we determined if the unit would have recovered its startup, no-load, and incremental costs if ran for its minimum run time at the dispatch point dictated by the prevailing day-ahead energy price. In last year's report, we used the results from the market run to determine the economic commitment status of a resource. This year, the MMU evaluated the commitment process against the market clearing engine prices to determine the economic commitment status of a resource.

During the process, we broke the resources into three groups based on the minimum run time of a resource–longer than 12 hours, one to 12 hours, and one hour or less. For the units with minimum run times longer than 12 hours, we looked if they would have been profitable if committed for the whole day, assuming a 24 hour minimum run time. For the units with minimum run times of one to 12 hours, we only checked two four hour peak times of each day (05:00-09:00 and 16:00-20:00 hours) and assumed a four hour minimum run time. For units with minimum run times of one hour or less, we assumed a one hour minimum run time. We then checked the potential revenue against the total commitment costs including startup, no-load and economic minimum energy cost. If the resulting revenues were positive, then we decided that the unit should have been committed in that day or hour.

In the second stage, if a unit was economic for commitment, we then identified the economic level of incremental output during hours when it was economic to produce energy based on real-time prices. In hours when the unit was not economic to run and on days when the unit

[104] The MMU calculates this metric by including all resources' total (reference level) capacity when calculating output gap percentages.
[105] The new metric is based on the approach used by Potomac Economics. Accordingly, the output gap calculations for 2015 and 2016 were reproduced and displayed along with 2017 data for comparison.

was not economic for commitment, the economic level of output was considered to be zero. To reflect the timeframe in which commitment decisions are actually made, this assessment was based on day-ahead market outcomes for non-quick-start units and real-time market outcomes for quick-start units (mostly gas turbines). This is because most of the energy for non-quick-start resources was awarded in the day-ahead market, whereas quick-start resources are generally committed on short notice and fully exposed to real-time prices. Therefore, we used day-ahead prices for non-quick-start resources and real-time prices for quick-start resources in assessing the output gap.

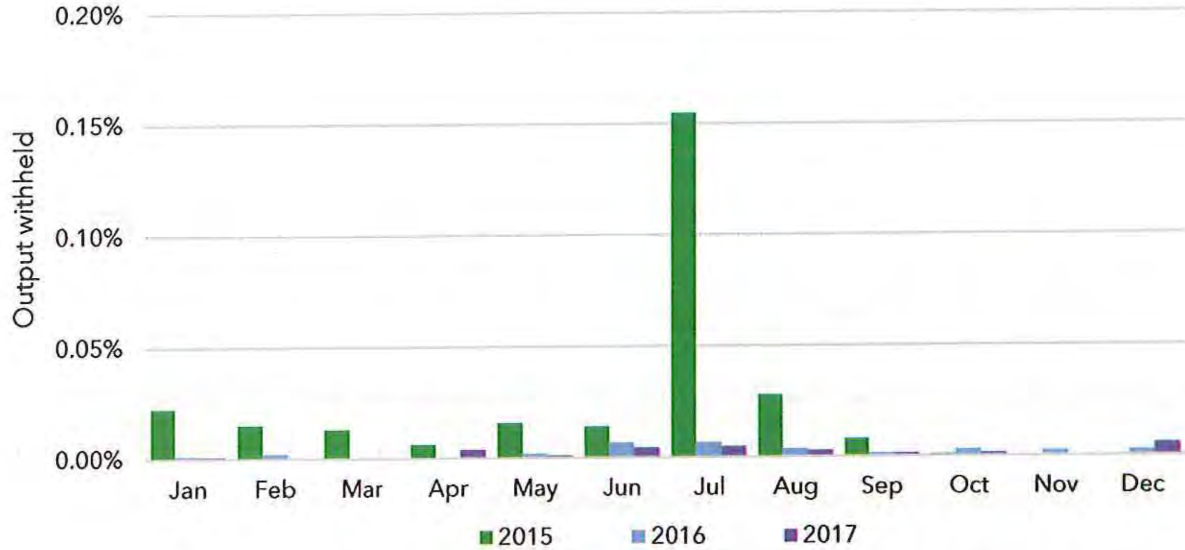
This year the MMU considered the 17.5 percent conduct threshold for the two frequently constrained areas and the 25 percent conduct threshold for the rest of the footprint to reflect the actual thresholds used in economic withholding mitigation.[106] In order to account for the discrepancy between a resource's offered capacity and the dispatched amount (because of possible limitations in real-time market conditions such as transmission constraints, operator actions or ramp limitations, virtual participants), an upward adjustment is made by taking the greater of the day-ahead scheduled or the real-time dispatched amount to reflect the actual amount of production.

Note that certain market conditions such as congestion (supplier location), supplier size, or high demand can create market power and facilitate economic withholding behavior. For this reason, the output gap is calculated as percentages of total economic output withheld compared to total reference capacity for the SPP footprint and for the two frequently constrained areas. In addition, the output gap is calculated for the largest three suppliers (market participant portfolios) in each area comparing the levels to those of the remaining suppliers. Similar to the last year's report, the annual calculations were run at varying levels of demand as a potential market condition that can affect the withholding outcome.

The results in Figure 6–11 below show the SPP footprint-wide monthly levels of the output gap from 2015 to 2017.

[106] The 2016 output gap calculations used only the 25 percent threshold level.

Figure 6–11 Output gap, monthly



The figure indicates that output gap levels were significantly higher in the first nine months of 2015 compared to the period afterwards through 2017. This could be related to the SPP footprint expansion on October 1, 2015 to include the Integrated System, which increased available supply in the market. After the market expansion, output gap levels were 0.007 percent or less in all months in 2016 and 2017, reflecting highly competitive participation in the market, overall.

Figure 6–12 through Figure 6–14 display the output gap calculated by demand level and participant size for the entire SPP market footprint and the two frequently constrained areas. In general more output is expected to be withheld at higher demand levels or by larger suppliers. However, at times, output may also be withheld in low load periods, as prices are often negative during the lowest 20 percent of load hours.

Figure 6–12 Output gap, SPP footprint

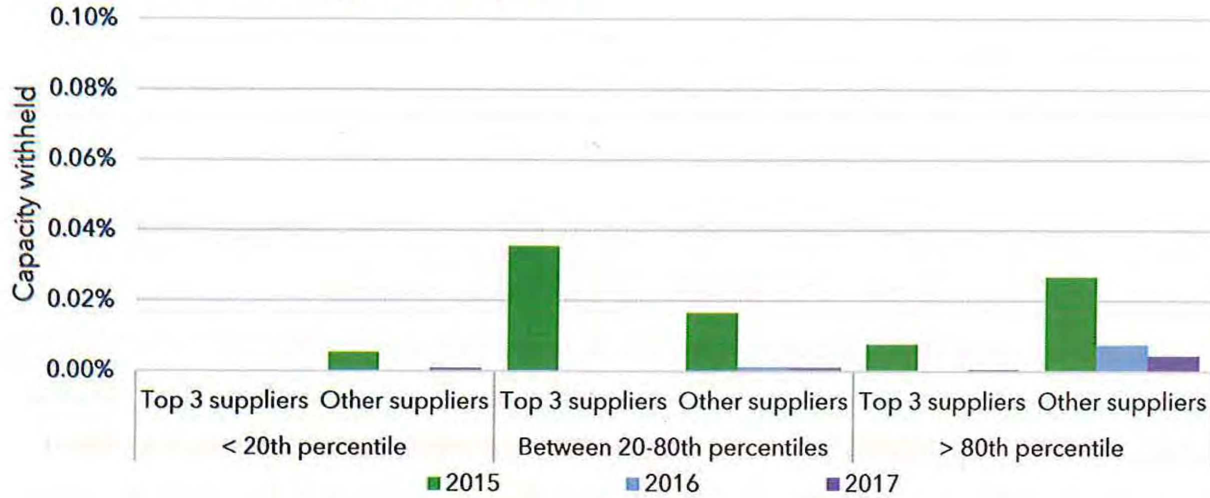


Figure 6–13 Output gap, Texas Panhandle frequently constrained area

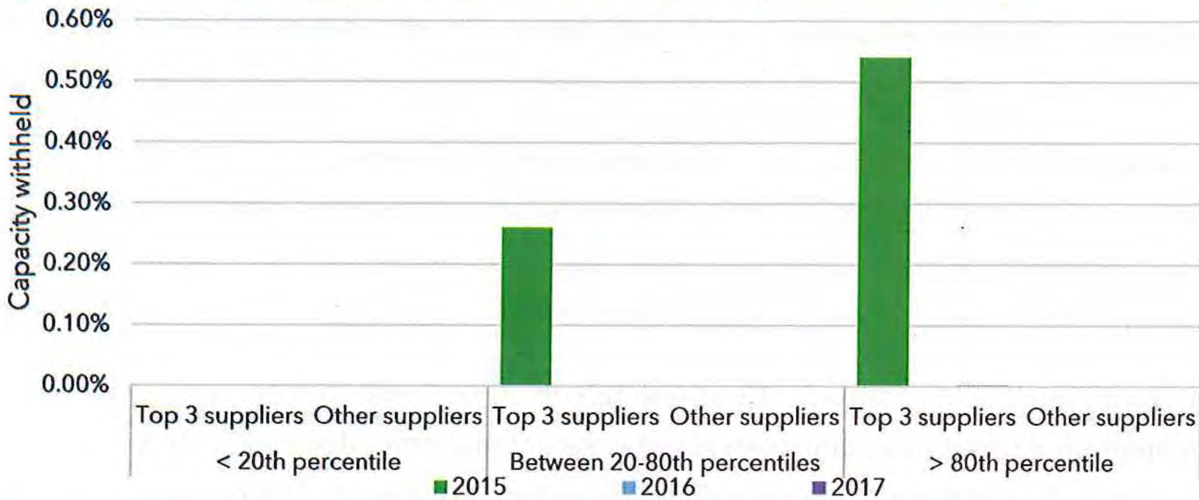


Figure 6–14 Output gap, Woodward frequently constrained area

Compared to 2015, all results indicate much lower levels of (economic) output withheld in 2016 and 2017, and particularly at higher demand levels. Specifically, there was no measurable output withheld in the frequently constrained areas in 2016 and 2017. These outcomes are consistent with the expectations of competitive market conduct.

6.2.4 UNOFFERED GENERATION CAPACITY (MEASURE FOR POTENTIAL PHYSICAL WITHHOLDING)

As part of the competitive assessment, we also looked into the potential physical withholding behavior by generators throughout the 2015 to 2017 period. Physical withholding refers to a conduct where a supplier derates a resource or otherwise does not offer it into the market. Physical withholding may include intentionally not following dispatch instructions, declaring false derates or outages, refusing to provide offers, or providing inaccurate capability limitations. Any economic generation capacity that is not made available to the market via derate, outage, or otherwise not offered to the market is considered for this analysis.[107,108]

We classified total economic capacity that was derated from respective reference levels by reason and duration. Deratings can take the form of planned outages approved in SPP's outage scheduling system, forced outages, or any undesignated unoffered capacity.[109] Any deratings from reference levels including partial deratings are considered in this analysis.

Derates were divided into short-term and long-term. Those with less than seven days duration were classified as short-term and the rest as long-term. This is because the economic capacity that was not offered short-term has more potential for physical withholding relative to long-term derates as it would be less costly–because of loss of sales–for a supplier to withhold capacity for a short duration of time.

As in the case for economic withholding, potential for physical withholding is also affected by various market conditions at the time offers are made including location (congestion), supplier size, or demand levels. Larger suppliers would be in a more advantageous position

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107 This analysis, in part, draws on "Assessment of the Market Monitoring Metrics for the SPP Energy Imbalance Service (EIS) Market," Potomac Economics, December 2010 and "2016 State of the Market Report For the New York ISO Markets," Potomac Economics, May 2017.

108 Economic capacity is determined in a similar way as in the output gap analysis in Section 6.2.3 by comparing resource's (cost-based) mitigated offer to the prevailing locational price.

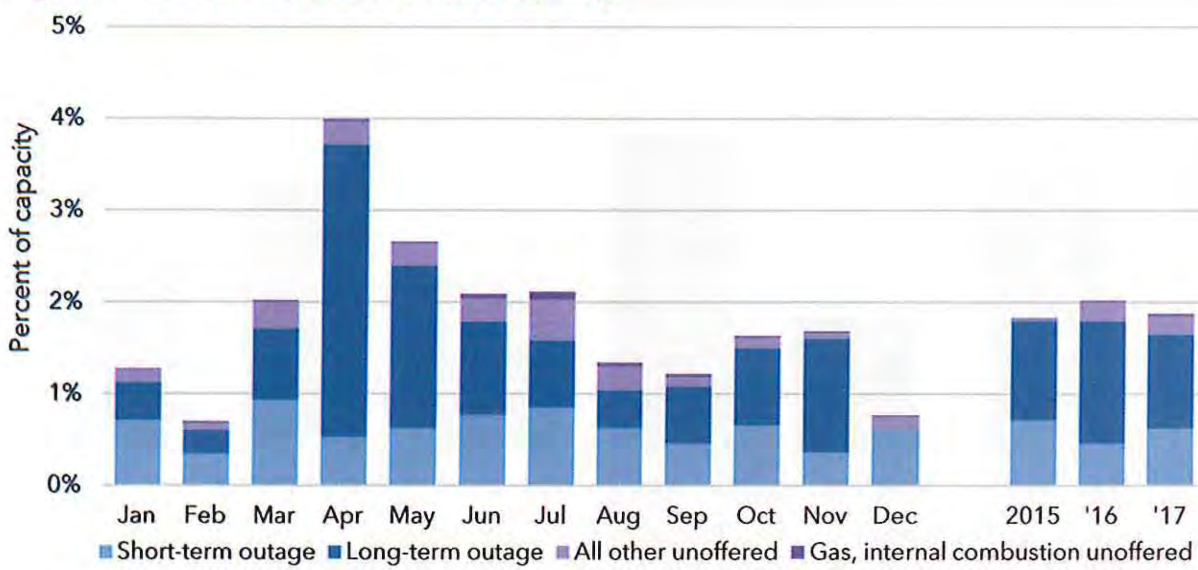
109 The planned maintenance outages by nuclear generation and unoffered capacity by hydro, wind and solar is excluded in this analysis.

to exercise market power. During tight market conditions, suppliers have more incentive and opportunity to physically withhold capacity for strategic reasons. In addition, scheduling maintenance outages in high demand periods may indicate a strategic behavior to create artificial shortages.

In the assessment, we considered derated and unoffered economic capacity both in day-ahead and real time. Similar to the output gap analysis, the commitment decisions were made based on day-ahead market outcomes for non-quick-start units and real-time market outcomes for quick-start units.[110] The unoffered capacity is calculated as the difference between the unit's economic capacity[111] and its offered maximum economic capacity operating limit during intervals when the unit was deemed economic (i.e., covering its costs given the clearing price).

The following figures show unoffered economic capacity as percent of total resource reference levels by month for the SPP footprint, by frequently constrained area, and by supplier (participant) size against varying load levels.[112]

Figure 6–15 Unoffered economic capacity



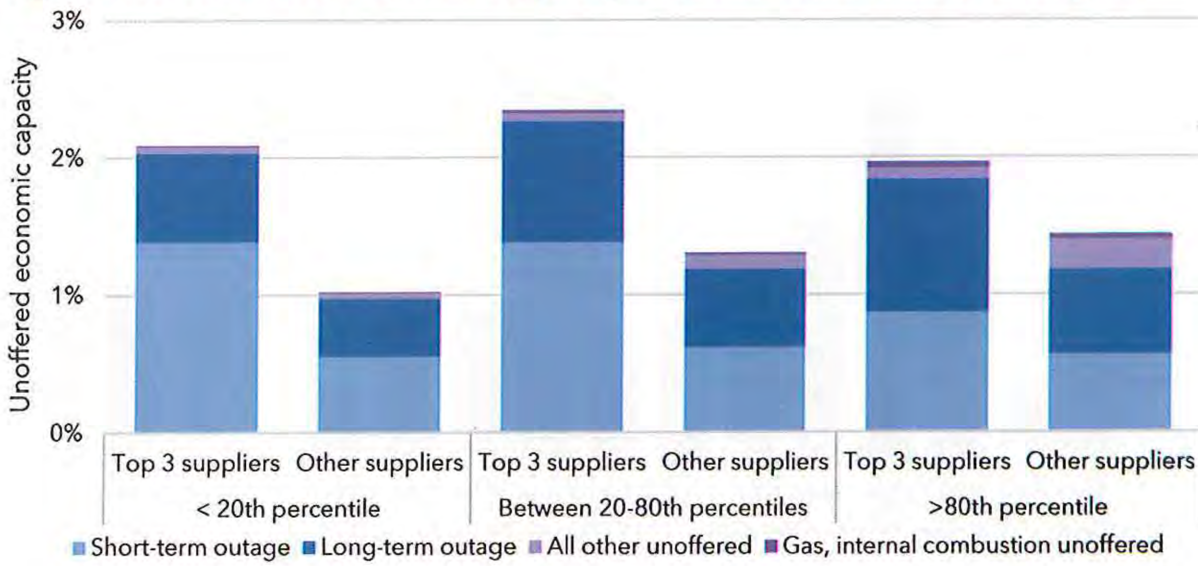
[110] See Section 6.2.3 for explanation of this method.
[111] Bounded by a resource's reference level.
[112] Unoffered capacity percentages are calculated out of the total reference levels of the corresponding area (i.e., SPP footprint or each of the two frequently constrained areas).

Figure 6–15 shows that on an annual average basis the total unoffered capacity equaled 1.8 percent in 2015, 2.0 percent in 2016, and 1.9 percent in 2017.

The figure also shows that the majority of the outages were long-term and concentrated during the fall and spring shoulder months. When short and long-term outages were excluded from the averages, the remaining unoffered capacity amounts to 0.03 percent, 0.22 percent, and 0.23 percent for 2015 through 2017. From a competitive market perspective, the results generally indicate reasonable levels of total unoffered economic capacity. The latter (net of outages) results, which are very low, could also be interpreted to indicate pressure on market participants, particularly on coal-fired resources, to offer–and maintain commitments–given their long-term coal contracts.[113] The general high levels of self-scheduling of supply offers in the SPP market could be another contributing factor in this outcome.

Figure 6–16 shows that short-term outages by either large suppliers or others do not rise with increasing load across the SPP footprint.

Figure 6–16 Unoffered economic capacity at various load levels, SPP footprint



On the other hand, unoffered economic capacity of gas (peaker) units by large suppliers rises with increased load. They are at very low levels of 0.01 percent, 0.02 percent, and 0.04

[113] Coal-fired resources may prefer to offer at times even below their mitigated offers to guarantee to be scheduled or dispatched. See also the offer price markup analysis earlier in Section 6.2.1 and the negative markup results reported therein.

percent of respective load levels. The unoffered economic capacity of gas units by other suppliers increases even at lower levels against load. Unoffered economic capacity compared to load is more apparent for the remaining resource types, however, it does not exceed 0.22 percent for either of the supplier groups.

Another take away from the results is that while long-term outages constitute the majority of total outages in the SPP footprint at higher load levels, short-term outages play a larger role in the two frequently constrained areas (see Figure 6–17 and Figure 6–18). Moreover, short-term outages in those two areas remained more or less the same as load levels increased.

Figure 6–17 Unoffered economic capacity at various load levels, Texas Panhandle area

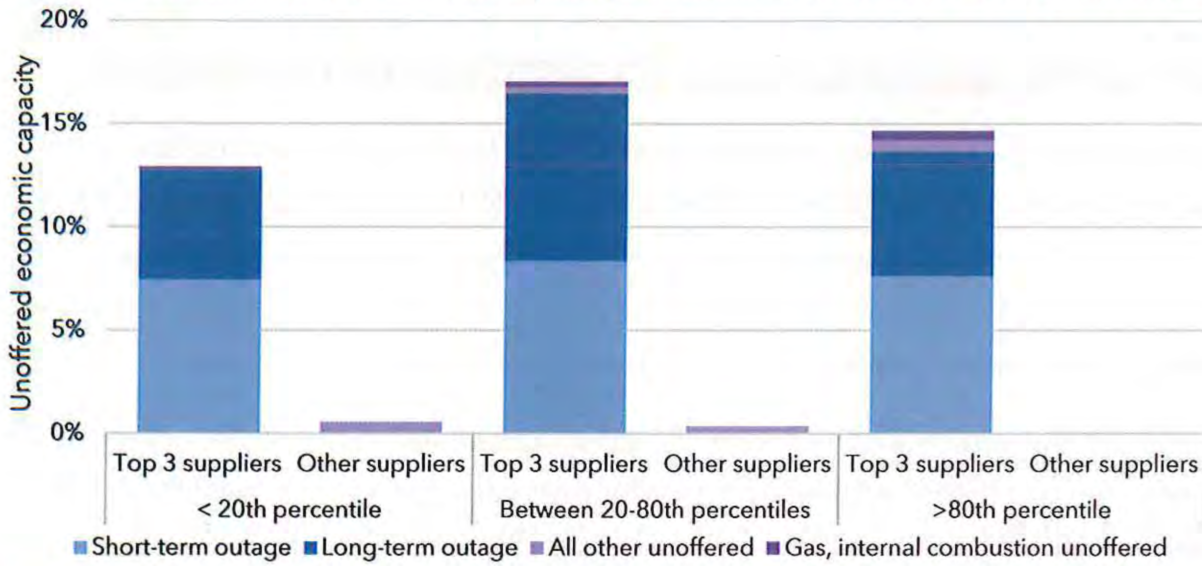
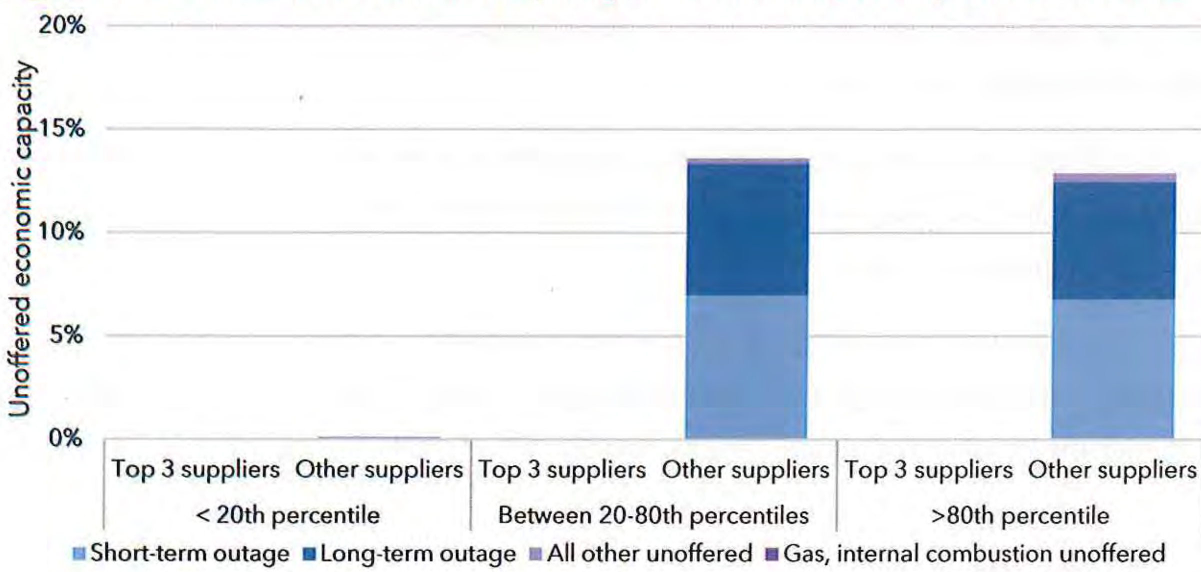


Figure 6–18 Unoffered economic capacity at various load levels, Woodward area



The SPP-wide outage data[114] show that most long-term outages were for maintenance (73 percent). Of those outages, most were scheduled during shoulder months (70 percent). Out of the short-term outages, approximately 40 percent were forced outages, with close to half of them in shoulder months.

In the Texas Panhandle and Woodward frequently constrained areas, 36 and 21 percent of the short-term outages respectively were forced outages with no clear seasonal trend. The Texas Panhandle frequently constrained area shows the dominance of larger participants in declaring long-term and short-term outages. These results are generally consistent with competitive market conduct.

6.3 OFFER BEHAVIOR DUE TO MITIGATION THRESHOLD

As discussed in the 2016 State of the Market report, the MMU has observed inefficient market behavior with regard to the mitigated threshold. The MMU submitted revision request 231 on the mitigation of locally committed resources to address this issue. The change was approved by the SPP board in October and is awaiting FERC filing and approval. This section highlights the nature of the concern and presents the SPP board approved solution.

SPP market rules require that market participants submit both a "market-based" energy offer curve and a "cost-based" mitigated energy offer curve. The offer cap of $1,000/MWh and the floor of -$500/MWh are the only limits to the energy offer curve. Market participants can submit any energy offer curve within these bounds. The market software will use the energy offer curve, unless the resource is mitigated. When mitigated, the mitigated offer curve will replace the energy offer curve.

In order for offers to be mitigated, the resource must fail all three of the following tests: local market power test, conduct test, and impact test. These three criteria for activating mitigation are described in Section 6.2.2.

Market participants directly affect the conduct test, sometimes referred to as the behavior test. When a market participant submits an energy offer that exceeds the mitigated offer by more than the thresholds described below, then the offer fails the conduct test.

[114] Covering all resources in the SPP market including nuclear, hydro, wind and solar generation.

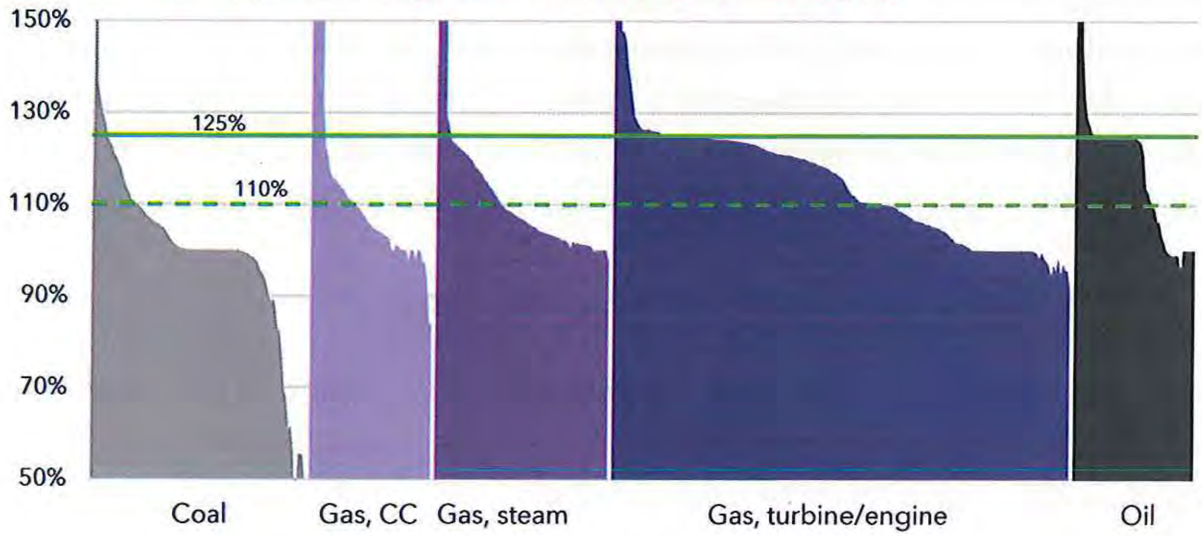
The thresholds are defined as:

- 10 percent above the mitigated energy offer for resources committed to address a local reliability issue,
- 17.5 percent above the mitigated energy offer for resources in a frequently constrained area, and
- 25 percent above the mitigated energy offer for all other resources.

As shown in Figure 6–19, there is again a noticeable plateau of bids at the 110 percent threshold (for gas turbines) and the 125 percent threshold (for oil-fired resources) for 2017. In the figure, the dashed line represents the 110 percent threshold, and the solid line represents the 125 percent threshold. The plateaus appear to be the result of participants offering their resources just under the conduct test thresholds in order to guarantee that they are not mitigated. This self-mitigating behavior at 10 percent can be problematic.

The purpose of mitigation for economic withholding is to protect the market from resources that have the unilateral ability to increase market prices. Resources flagged for economic withholding mitigation have local market power, and allowing inflated market offers only gives them more opportunity to exercise market power. Resources that are committed for a local reliability issue, often for voltage support, should not fall into this category. Even though these resources are needed and must be committed, they are committed outside of the market clearing engine logic, and often do not have the ability to increase prices as they are frequently dispatched down to minimum.

Figure 6–19 Mitigation energy offer mark-up by fuel category



Resources receiving a commitment for local reliability (about 0.4 percent of all commitments in 2017) are subject to a 10 percent mitigation threshold for the duration of their commitment. The market system replaces market offers that are more than 10 percent above the mitigated offer with the mitigated offer for that commitment. Resources that do not receive commitments for local reliability are not at risk of being mitigated down to the mitigated offer level for offers between 10 percent and 25 percent above the mitigated offer (17.5 percent for resources in designated frequently constrained areas, which accounts for nine percent of all resources).

When resource owners decide on a market offer for a resource that has the possibility of receiving a reliability commitment, the owner may factor in the risk of being mitigated to the mitigated offer level for offers above 10 percent. All other resource owners do not face this risk and will not have their market offer reduced to the mitigated offer level, if the market offer does not exceed 25 percent above the mitigated offer. By converting the 10 percent threshold for reliability commitments to a 10 percent cap, the risk of making an offer between 10 percent and 25 percent above the mitigated offer would be the same for all resource owners. This is a subtle but important risk for the small number of market participants that may be committed for reliability commitments. These resource owners are subject to a higher level of risk through no fault of their own.

The MMU recommended in its 2016 report that mitigation measures for resources committed for a local reliability issue be treated separately from the mitigation measures for economic withholding. Resources that fall into this category are not subject to the three tests associated with economic withholding, which is appropriate. The MMU submitted revision request 231[115] to the Market Working Group in May 2017, which proposed converting the 10 percent threshold for local reliability mitigation to a 10 percent cap. The revision request received SPP board approval in October, and is awaiting FERC filing and approval.

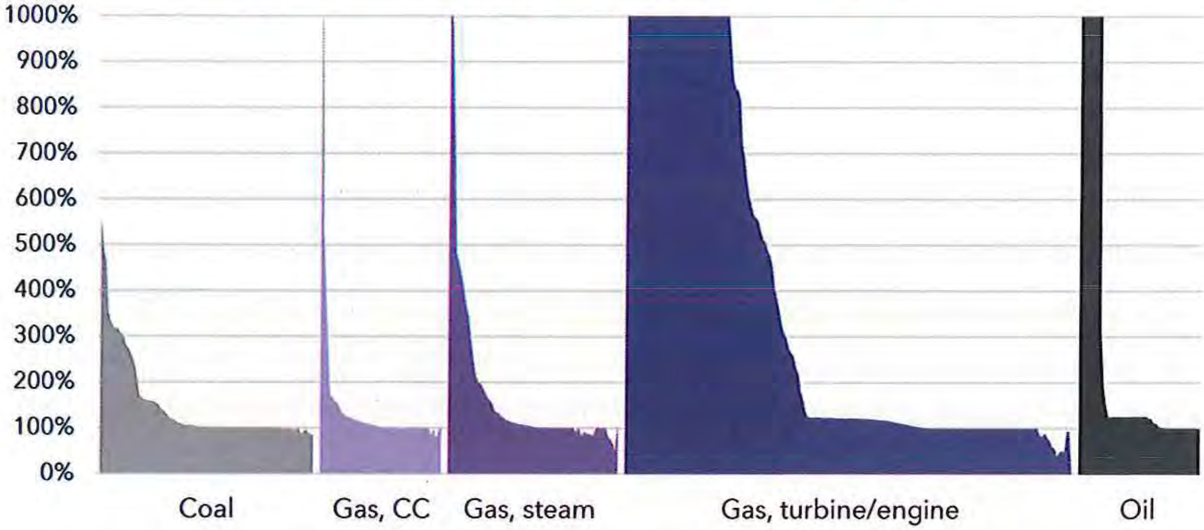
6.4 START-UP AND NO-LOAD BEHAVIOR

Similar analysis with no-load and start-up offers indicated that many market participants were making start-up and no-load offers considerably above their mitigated offer levels as shown

[115] Revision request 231 Mitigation of locally committed resources.

in Figure 6–20. Nonetheless, start-up mitigation only occurred in approximately three percent of intervals in 2017.

Figure 6–20 Mitigation start-up offer mark-up by fuel category



Further analysis and discussion indicated that start-up mitigation was most frequently due to major maintenance costs inherent in the repeated heating and cooling process of starting-up and shutting down units. As the purpose of the mitigated offer is to prevent undue costs not directly tied to a commitment or dispatch decision from being imposed on the market, revision request 245 was developed.[116] This revision request will allow the inclusion of major maintenance costs that can be directly tied to the number of run hours or starts to be included in the mitigated offers for start-up and no-load and properly evaluated by the market clearing engine in determining commitments. Revision request 245 has been approved by the appropriate stakeholder groups and is expected to be filed in April 2018. The MMU is supportive of revision request 245 and feels that it will encourage more units to move into the market commitment status, which will lead to more efficient price formation and reduce starts for units that are less efficient.

6.5 COMPETITIVE ASSESSMENT SUMMARY

Overall, the structural and behavioral metrics indicate that the SPP markets were very competitive in its first four years. The market share, HHI, and pivotal supplier analyses all

[116] RR245 Mitigated Start-Up and No-Load Offer Maintenance Cost.

indicate minimal potential structural market power in SPP markets outside of areas that are frequently congested. There were two designated frequently constrained areas in 2017 where the potential concerns of local market power were the highest. Ongoing analysis shows existing mitigation measures have been an effective deterrent in preventing pivotal suppliers from unilaterally raising prices.

Behavioral indicators were also assessed through the analysis of actual offer or bid behavior (i.e., conduct) of the market participants and the impact of such behavior on market prices to look for the exercise of market power. One such indicator, the negative offer price mark-ups in 2017 show substantially elevated negative offer levels compared to those of 2016. This could occur where–particularly coal–generators decide to offer below their marginal cost to maintain commitments or when wind units become marginal and their (negative) offers clear the market.

Economic withholding mitigation was still at a low level in absolute terms. In particular, the incremental energy mitigation was extremely low in both the day-ahead and real-time markets, at around 0.01 percent in each market for 2017. The overall mitigation frequency of start-up offers in 2017 were at the lowest levels since market started in 2014 as the combined frequency of mitigation of start-up offers for day-ahead, reliability unit commitment, and manual commitments decreased to 3.2 percent in 2017 from 3.8 percent in 2016. While the frequency of no-load, operating reserve, and incremental energy mitigation increased in 2017, the level of mitigation remained low overall. The overall mitigation frequency levels experienced in 2017 are consistent with the levels experienced in other markets.

The system wide output gap results show a very low-level–less than 0.007 percent–of economic withholding in all months in 2016 to 2017 across the SPP footprint. Compared to 2015, all results indicate much lower levels of output withheld in 2016 and 2017, and were particularly lower at higher demand levels. In the two frequently constrained areas, there was no measurable output withheld in 2016 and 2017. These low levels of economic output withheld is consistent with competitive market conduct.

The newly introduced metric, the average unoffered economic capacity was around two percent in the 2015 to 2017 period and was at 1.9 percent in 2017. The majority of the outages were long-term outages, and were primarily the result of maintenance in the shoulder months of fall and spring. The results are generally consistent with the workings of a typical competitive market.

Meanwhile, the very low level–less than one percent–of unoffered capacity net of outages could indicate a pressure on market participants to offer–and maintain commitments–given their longer term agreements. The general high levels of self-committing supply in the market could be another factor in the low levels of unoffered capacity.

Overall, the SPP Integrated Marketplace provides effective market incentives and mitigation measures to produce competitive market outcomes particularly during market intervals where exercise of local market power is a concern. The competitive assessment in this report provides evidence that market results in 2017 were workably competitive and that the market required mitigation of local market power infrequently to achieve those outcomes. Nonetheless, mitigation remains an essential tool in ensuring that market results are competitive during periods when such market conditions offer suppliers the potential to abuse local market power.

7 RECOMMENDATIONS

One of the core functions of a market monitor as defined by FERC in Order No. 719 is "to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes." The MMU accomplishes this responsibility through many forums, including but not limited to active participation in the SPP stakeholder meetings process, commenting on FERC notices of proposed rulemakings, submitting comments at FERC on SPP filings, and making recommendations in the Annual State of the Market report. This section outlines the MMU recommendations to SPP and stakeholders to address our concerns with the current market design.

Further, this section highlights both new recommendations as well as recommendations made in prior reports. For each recommendation, we present the reasons for our recommendation and assign a priority. We also identify the current status of previous recommendations. Overall, SPP and its stakeholders have made significant progress on most outstanding MMU recommendations. Section 7.5 below lists the status of past and current annual report recommendations.

7.1 INCREASE MARKET FLEXIBILITY

The SPP market needs more flexible generation to meet increasing ramping requirements as renewable generation levels continue to increase (see Section 2.5) and as renewable generation dominates the interconnection queue over the next several years (see Section 2.3.3). As presented earlier in this report, we have seen a doubling of the frequency of negative priced intervals, and an increase in short-term transitory price spikes related to scarcity of ramping. Because of the variable output nature of these renewable energy resources, the market needs increasing capability to respond to the inevitable fluctuations in order to promote efficient market outcomes and ensure reliability. At this juncture, it is imperative for the RTO and its members improve its market mechanisms to address this growing concern.

While there is no single solution, there are existing ways that SPP can increase market flexibility. We outline these solutions below.

7.1.1 DEVELOP A RAMPING PRODUCT

A ramping product that incents actual, deliverable flexibility can send appropriate price signals to value resource flexibility. This resource flexibility can help prepare the system for fluctuations in both demand and supply that result in transient short-term positive and negative price spikes.

Today, the SPP dispatch engine solves for only the current interval and has no look-ahead logic to ensure that there is enough rampable capability to meet the needs of future intervals. This can cause quick-ramping resources to be dispatched to their maximum limits in one interval, and then, in the next interval, there is a shortage of ramp because the only resources able to move have slower ramp rates. In these cases, SPP can have plenty of capacity on-line, but not enough rampable capacity, which can result in scarcity pricing.

As noted above, SPP's scarcity events are very short-term, transient events that are frequently a result of a shortage of rampable capacity. A ramping product will compensate resources for holding back capability in one interval so it can be used as energy in a future interval. This will reduce the frequency of scarcity events and provide value to the resources providing ramping capability.

Both the California ISO and Midcontinent ISO have designed and successfully implemented ramping products. While SPP stakeholders have discussed the possibility of a ramping product for the last several years, the development of a ramping product has only now risen to the top of stakeholder priorities to be addressed in the coming months. We agree with the assessment of SPP and its stakeholders that this is a high priority initiative and recommend that a ramping product be designed in 2018.

7.1.2 IMPROVE RULES RELATED TO DECOMMITTING RESOURCES

Over-commitment of resources in real time suppresses prices and leads to increased make-whole payments. This can be caused by changing conditions between the time a resource is locked into a commitment by the market software and the time the resource actually comes on-line. The MMU recommends that SPP and its stakeholders address this issue by enhancing its markets rules to economically decommit a resource that is planned to start.

Resources are frequently committed by the market software well in advance of when they are actually required to start. This commitment is based on the known assumptions at the time the market engine clears the market. However, conditions change over time. For instance, load forecasts, wind forecasts, and outages change, and resources trip off-line. Resources are committed because the market software evaluates it to be profitable over that study period. When assumptions change, the resource may no longer be profitable; however, the start-up order is not cancelled.

Stakeholders have prioritized the development of design changes to economically decommit a resource that was planned to start but is no longer needed once the resource reaches the time to start. We agree with the assessment and priority of this initiative. The MMU recommends that decommit logic be developed in 2018.

7.1.3 ENHANCE MARKET RULES FOR ENERGY STORAGE RESOURCES

With the increase in wind penetration in the SPP market, there is not only a need for resource flexibility, but also for storage where the frequency of negative prices has increased, as discussed in Section 4.1.6. Stored energy resources have the potential to address both the need for flexibility and reduce the incidence of negative prices. However, SPP's current tariff does not easily allow these resources to integrate in our market. In order to capture the benefits of these new technologies, a new market design needs to be developed.

Though SPP, its members and stakeholders, and the MMU have discussed ways to incorporate stored energy resources in the past, development of tariff language to support energy storage resources has not yet occurred. We believe that the lack of an effective market design may be an influencing factor limiting the integration of storage resources in the SPP market. Enhancing market rules will allow these new resources to enter the market to help address the incidence of negative prices and add needed resource flexibility.

FERC issued an order requiring RTO/ISOs to develop market rules to promote energy storage in February 2018.[117] The MMU agrees with FERC and looks forward to discussion on this topic going forward.

[117] https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf

7.2 IMPROVE MARKET EFFICIENCY

One of the key benefits of the day-ahead market is the unit commitment process. Market participants offer resources into the day-ahead market and the market optimization process minimizes production costs. When participants self-commit resources, this can create inefficient market outcomes. Furthermore, market inefficiencies also occur when resources with forecasted generation–such as wind–are withheld from the day-ahead market run, even though their expected generation levels are much higher in the day-ahead reliability unit commitment process. Both of these inefficiencies can result in suppressed, and potentially negative, market prices. Addressing these issues, can improve market results and provide more efficient price signals. We recommend that SPP and its stakeholders address both of these issues.

7.2.1 ADDRESS INEFFICIENCY CAUSED BY SELF-COMMITTED RESOURCES

Market participants have identified several reasons why they self-commit resources in the market. Some of these reasons include contract terms for coal plants, low gas prices that reduce the opportunity for coal units to be economically cleared in the day-ahead market, long startup times, overtime costs, increased major maintenance costs, and a risk-averse business practice approach. However, it is imperative to minimize the need to self-commit resources to realize the full benefits of SPP's market. While there may not be a single reason causing market participants to self-commit resources, there can be ways that SPP and its stakeholders can work to minimize the need to self-commit.

For instance, long lead time and long run time resources are often self-committed in the market and contribute to depressing prices in the SPP market. These resources are not appropriately evaluated in the current structure of the market and can be committed by the market participant during uneconomic periods. The current clearing engine logic does not evaluate commitments beyond the 24-hour period of the next operating day. The creation of a market process that economically evaluates resources over a longer period will allow for more efficient market solutions, as well as decreased production costs.[118]

In the current design, a resource that is required to run for multiple days is not evaluated by the day-ahead market to see if the resource is economic over its minimum run time. The clearing engine may see that it is economic on the first day and issue the commitment, and then in future days the resource must stay on even if it is uneconomic. As such, many resources that have multi-day minimum run times avoid the market clearing process and instead self-commit in the market based not on an evaluation by the market, but on their own evaluation of market conditions. This is not the optimal solution for the SPP market as it removes the ability for the SPP market software to evaluate and commit the resources economically relative to all other resources in the market.

Adding multi-day unit commitment logic is at the top of the current stakeholder market design initiative list. The MMU agrees that this should be a priority item and supports SPP and its stakeholders in attempting to address self-commitments through the development of a multi-day unit commitment process. More broadly, however, the MMU recommends that SPP and its stakeholders continue to explore and develop ways to reduce the incidence of self-commitment of resources outside of the market engine. We view this as a high priority for SPP and its stakeholders as this will enhance market efficiency and improve price signals.

7.2.2 ADDRESS INEFFICIENCY WHEN FORECASTED RESOURCES UNDER-SCHEDULE DAY-AHEAD

Our analysis shows that, on average, 82 percent of forecasted wind generation was scheduled in the day-ahead market in 2017, compared to 89 percent in 2016, and 92 percent in 2015. This under-scheduling continues to grow as more wind is installed. On average for the year, over 1,200 MWh of real-time wind generation was not included in the day-ahead market.[119] When this happens, we frequently observe day-ahead prices exceeding real-time prices. While we also observe virtual participants placing bids and offers at wind locations during these times, we find that price convergence in absolute terms is not improving. As a

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[118] This would be different from the current multi-day reliability unit commitment process.
[119] From a reliability standpoint, the reliability unit commitment assesses wind resources at forecasted levels. However, the reliability unit commitment process cannot economically decommit resources scheduled by the day-ahead market.

result, the efficiency of the day-ahead unit commitment process is reduced. In this case, other non-wind resources may be overcommitted in the day-ahead market, which results in real-time prices lower than day-ahead prices.

Systematic under-scheduling of wind resources in the day-ahead market can contribute to distorting market price signals, suppressing real-time prices, and affecting revenue adequacy for all resources. Therefore, the MMU recommends that SPP and its stakeholders address this issue through market rules changes that reduce the incidence of under-scheduling of forecasted supply of resources in the day-ahead market. We consider this a high priority as it helps to enhance market efficiency and improve price signals.

7.3 FURTHER ENHANCE ALIGNMENT OF PLANNING PROCESSES WITH OPERATIONAL CONDITIONS

Enhancing the accuracy of planning processes with operational realities enables SPP and its members to more effectively plan for future system needs and conditions. Many of the challenges outlined in this report–including increased congestion, negative prices, and low generator net revenues–as well as improvements–such as the addition of the Woodward phase-shifting transformer–are, in part, a reflection of planning decisions. The more the planning process can learn from and incorporate operational information, the more planning can identify and address concerns in advance of market operations. The MMU understands that much work has been done by SPP and stakeholders over the past few years to improve and align the planning and operational processes. For instance, SPP in its latest Integrated Transmission Planning manual introduced an assessment for persistent operational needs and the criteria for identifying these needs.[120] The MMU has identified two additional areas where further alignment would be beneficial. Specifically, the economic studies and resource adequacy processes are two planning processes that could benefit by further aligning with operational information.

First, SPP proposed to set the interim default variable operations and maintenance costs for wind resources to $0/MWh in revision request 276. While the Economic Studies Working

[120] See SPP Integrated Transmission Planning Manual (dated July 20, 2017 pending FERC approval of Tariff language), including sections 4.4, 5.3.4, and 6.1.4 (available at https://www.spp.org/documents/22887/itp%20manual%20version%202.0.pdf).

Group rejected this revision request and narrowly passed an amended version of this request, the Market Operations and Policy Committee reversed direction and accepted the original SPP proposal. Based on the review of operational information by the MMU, we find that variable operations and maintenance costs for wind resources are closer to $0/MWh. Using a value in economic planning studies inconsistent with operational realities will distort how stakeholders evaluate the benefits and costs of transmission upgrades. Thus, we recommend that as a permanent solution is designed, the approach should seek to align the variable operations and maintenance costs with the appropriate operational realities.

Second, as discussed earlier in this report, SPP excludes resources without firm transmission from resource adequacy calculations.[121] Even at conservative planning levels, this ignores several hundred megawatts of real-time generation, understating the true generation that is available to SPP at peak load conditions. As shown in our peak available capacity metric (Section 2.3.2), we find that a significant amount of generation is available at peak loads, which helps to contribute to the market challenges noted in this report. Directly recognizing the different levels of generation availability could help inform stakeholders and decision-makers in formulating decisions on generation and capacity needs. Thus, we recommend that SPP highlight the full set of generation that exists as part of the resource adequacy process.

7.4 ADDRESS PREVIOUS RECOMMENDATIONS

The MMU has provided recommendations to improve market design in each of our previous Annual State of the Market reports since the launch of the integrated marketplace in 2014. Overall, SPP and its stakeholders have found ways to effectively address many of our concerns. However, there are a number of recommendations that remain outstanding. A description of each of these recommendations, their currents status, and our assessment of their priority are outlined below.

[121] SPP also excludes resources without physical supply or a firm pipeline reservation.

7.4.1 CONVERT NON-DISPATCHABLE VARIABLE ENERGY RESOURCES TO DISPATCHABLE

In the 2015 Annual State of the Market report, the MMU identified non-dispatchable variable energy resources as a concern because of their adverse impact on market price and system operations. These resources exacerbate congestion, reduce prices for other resources, increase the magnitude of negative prices, cause the need for market-to-market payments, and force manual commitments of resources that can increase uplifts. Going forward, resource flexibility is essential to integrate an increasing volume of wind generation in the SPP market. FERC demonstrated strong support for the elimination of most instances of non-dispatchable resources with the approval of a rule change for the New England market in December 2016.[122] Furthermore, FERC also rejected California ISO's proposal to extend the transition period for protective measures related to non-dispatchable variable energy, thus requiring dispatchability.[123]

In the summer and fall of 2017, SPP and its stakeholders discussed the impacts and implications of non-dispatchable variable energy resources on market outcomes at the Market Working Group. By the end of the year and into early 2018 multiple proposals were brought forth and discussed at the Market Working Group. The Market Working Group passed a proposal by SPP at the February 2018 meeting that required full conversion of non-dispatchable variable energy resources. The MMU strongly supported this proposal and will continue to support this proposal as it continues along the SPP stakeholder process.

Because of the need to increase market flexibility and to address adverse market outcomes associated with non-dispatchable variable energy resources, the MMU strongly recommends that SPP and its stakeholders address this issue. The MMU considers this to be a high priority recommendation.

7.4.2 ADDRESS GAMING OPPORTUNITY FOR MULTI-DAY MINIMUM RUN TIME RESOURCES

Resources with minimum run times greater than two days have the opportunity to game the market. The current market rules limit make-whole payments to the as-committed market offers for the first two days of a resource's minimum run time. However, after the second day,

[122] See FERC Docket Nos. ER17-68-000 and ER17-68-001.
[123] See FERC Docket No. ER17-1337-000.

no rule exists to limit make-whole payments for a resource that increases its offers from the third day onward until the resource's minimum run time is satisfied. For resources with minimum run times greater than two days, the market participant knows that the resource is required to run and can increase their market offers after the second day to increase make-whole payments.

The MMU developed and presented a proposed solution to the Market Working Group in March 2017. This solution would have capped the market offer after the first day to the ratio of the market offers to the mitigated offers. The proposal was rejected by the Market Working Group. The MMU successfully appealed the issue to the Market and Operations Policy Committee (MOPC) which remanded this topic back to the Market Working Group for further review in July 2017. Ongoing discussions among stakeholders have continued into early 2018, and after much discussion the Market Working Group has identified a potential solution. The current proposed solution would limit the make-whole payments for any resource with multi-day minimum run times to the lower of the market offer or the mitigated offer after the first day for resources that bid at or above their mitigated offer on the first day.

The MMU strongly recommends that SPP and its stakeholders address the gaming opportunity that exists for resources with minimum run times greater than two days and supports the current direction of the Market Working Group. Our understanding is that all other RTO/ISO markets address this item. Addressing this matter in a timely manner is a high priority for the MMU.

7.4.3 CONVERT THE LOCAL RELIABILITY MITIGATION THRESHOLD TO CAP

In the 2016 Annual State of the Market report the MMU recommended converting the 10 percent mitigation threshold for local reliability commitments to a 10 percent cap. This recommendation addresses an unbalanced risk associated with mitigation of resource commitments for local reliability.

When market participants decide on a market offer for a resource that has the possibility of receiving a local reliability commitment, the participant must factor in the risk of being mitigated to the mitigated offer level for offers above 10 percent above the mitigated offer. All other resources do not face this risk and will not have their market offer reduced to the mitigated offer level if the market offer does not exceed 25 percent above the mitigated offer. By converting the 10 percent threshold for reliability commitments to a 10 percent cap, the risk of local market power mitigation for offers between 10 percent and 25 percent above the mitigated offer would be similar as for all other resources. This is a subtle but important risk for the small number of market participants exposed to local reliability commitments that are outside of the market.

The Market Working Group passed a proposal in August presented by the MMU to convert the 10 percent mitigation threshold for local reliability commitments to a 10 percent cap as part of a suite of changes and clarifications associated with mitigation. This change was approved by the SPP board of directors in October and is pending a FERC filing. The MMU strongly supports this change and will support this when filed at FERC.

7.4.4 REPLACE DAY-AHEAD MUST OFFER, ADD PHYSICAL WITHHOLDING PROVISION

FERC rejected SPP's proposal to remove the day-ahead must offer requirement and indicated that it would consider removal of the requirement if it were paired with additional physical withholding provisions.

While the MMU remains concerned with the current day-ahead must offer requirement, we recommend that further consideration of this issue be a low priority. The MMU will continue to track market performance concerns related to this provision and will consider raising the priority on this matter if further issues are identified or current issues are exacerbated. Otherwise, we regard other matters as having higher impacts to and priority for development at this time.

7.5 RECOMMENDATIONS UPDATE

The table below lists all of the Annual State of the Market recommendations that were closed in 2016 through the date of this report, those that remain open, and those that are new. Recommendations closed prior to the completion of the previous year's report do not appear in this table. To review closed recommendations that are not covered in this report, please consult earlier reports. All previous annual reports can be found at https://www.spp.org/spp-documents-filings/?id=18512.

Figure 7–1 Annual State of the Market recommendations update

Recommendation	Report year	Current status
1. Develop multi-day commitment process	2017	Planned for stakeholder consideration
2. Address under-scheduling of wind	2017	Awaiting stakeholder engagement
3. Develop ramping product	2017	Planned for stakeholder consideration
4. Enhance unit decommitment logic	2017	Planned for stakeholder consideration
5. Develop energy storage design	2017	Response to FERC order in progress
6. Continue alignment of planning processes with operational conditions	2017	Awaiting consideration and engagement
7. Local reliability commitment mitigation threshold conversion to a cap	2016	Awaiting FERC filing
8. Non-dispatchable variable energy resource transition to dispatchable variable energy resource status	2015	Appeal in progress to SPP board
9. Improved quick-start logic	2014	Awaiting FERC order
10. Manipulation of make-whole payment provisions (multiple items)	2014	Across midnight hour - in progress Out-of-merit payments - withdrawn by MMU Jointly-owned units - in progress Regulation - approved by FERC, awaiting implementation
11. Day-ahead must offer requirement and physical withholding	2014	Day-ahead must offer - request denied by FERC pending physical withholding additions
12. Allocation of over-collected losses	2014	Awaiting FERC approval
13. Increase conduct test thresholds in frequently constrained areas	2014	Withdrawn by MMU

COMMON ACRONYMS

AECC	Arkansas Electric Cooperative Corporation
AECI	Associated Electric Cooperative, Inc.
AEP/AEPM	American Electric Power
ARR	auction revenue rights
BEPM	Basin Electric Power Cooperative
BSS	bilateral settlement schedules
BTU	British thermal unit
CC	combined-cycle
CDD	cooling degree days
CHAN	City of Chanute (Kan.)
CT	combustion turbine
DA	day-ahead
DAMKT	day-ahead market
DA RUC	day-ahead reliability unit commitment
DISIS	definitive interconnection system impact study
EDE/EDEP	Empire District Electric Co.
EHV	extra high voltage
EIA	Energy Information Administration
EIS	energy imbalance service
ERCOT	Electric Reliability Council of Texas
FCA	frequently constrained area
FERC	Federal Energy Regulatory Commission
GI	generation interconnection
GLDF	generator to load distribution factor
GMOC/UCU	Greater Missouri Operations Company (KCPL)
GRDA/GRDX	Grand River Dam Authority
GSEC	Golden Spread Electric Cooperative, Inc.
GW	gigawatt
GWh	gigawatt hour
HDD	heating degree days
HHI	Herfindahl-Hirschman Index

HMMU	Harlan (Iowa) Municipal Utilities
HVDC	high-voltage direct current
IA	interconnection agreement
ID RUC	intra-day reliability unit commitment
IDC	interchange distribution calculator
INDN	City of Independence (Mo.)
IOU	investor owned utility
IPP	independent power producer
IS	Integrated System
ISO	independent system operator
ITP	Integrated Transmission Plan
JOU	jointly-owned unit
KBPU	Kansas City (Kan.) Board of Public Utilities
KCPL/KCPS	Kansas City Power & Light
KMEA	Kansas Municipal Energy Agency
KPP	Kansas Power Pool
kV	kilovolt (1,000 volts)
LES/LESM	Lincoln (Nebr.) Electric System
LIP	locational imbalance price
LMP	locational marginal price
MCC	marginal congestion component
MEAN	Municipal Energy Agency of Nebraska
MEC/MECB	MidAmerican Energy Company
MEUC	Missouri Joint Municipal Electric Utility Commission
MIDW	Midwest Energy Inc.
MISO	Midcontinent Independent Transmission System Operator
MLC	marginal loss component
MM	million
MMBtu	million British thermal units (1,000,000 Btu)
MMU	Market Monitoring Unit
MW	megawatt (1,000,000 watts)
MWh	megawatt hour
MWP	make-whole payment

MRES	Missouri River Energy Services
NDVER	non-dispatchable variable energy resource
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NPPD/NPPM	Nebraska Public Power District
NSP/NSPP	Northern States Power Energy
NWPS	Northwestern Energy
O&M	operation and maintenance
OGE	Oklahoma Gas & Electric
OMPA	Oklahoma Municipal Power Authority
OOME	out-of-merit energy
OPPD/OPPM	Omaha Public Power District
OTPW/OTPR	Otter Tail Power Company
PJM	PJM Interconnection, LLC
PEPL	Panhandle Eastern Pipe Line
PISIS	preliminary interconnection system impact study
RC	reliability coordinator
RNU	revenue neutrality uplift
RR	revision request
RSG	reserve sharing group
RT	real time
RTBM	real-time balancing market
RTO	regional transmission organization
RUC	reliability unit commitment
SC	simple-cycle
SECI/SEPC	Sunflower Electric Power Corporation
SPA	Southwestern Power Administration
SPP	Southwest Power Pool, Inc.
SPRM	City Utilities of Springfield (Mo.)
SPS	Southwestern Public Service Company
ST	steam turbine
ST RUC	short-term reliability unit commitment
TCR	transmission congestion right

TEA	The Energy Authority
TNSK	Tenaska Power Service Company
UGPM	Western Area Power Administration, Upper Great Plains
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WFEC/WFES	Western Farmers Electric Cooperative
WR/WRGS	Westar Energy, Incorporated