# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>SUMMER 2014 SUMMARY</td>
<td>2</td>
</tr>
<tr>
<td>PRICES</td>
<td>3</td>
</tr>
<tr>
<td>CONGESTION</td>
<td>23</td>
</tr>
<tr>
<td>GENERATION</td>
<td>29</td>
</tr>
<tr>
<td>UNIT COMMITMENT</td>
<td>43</td>
</tr>
<tr>
<td>VIRTUAL ENERGY</td>
<td>49</td>
</tr>
<tr>
<td>TRANSMISSION CONGESTION RIGHTS</td>
<td>57</td>
</tr>
<tr>
<td>UPLIFT</td>
<td>60</td>
</tr>
<tr>
<td>List of acronyms</td>
<td>69</td>
</tr>
</tbody>
</table>

## DISCLAIMER

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Copyright © 2014 by Southwest Power Pool, Inc. Market Monitoring Unit. All rights reserved.
• The Southwest Power Pool Integrated Marketplace began on March 1, 2014. The new market contains:
  o Day-Ahead Market with Transmission Congestion Rights
  o Reliability Unit Commitment process
  o Real-Time Balancing Market
  o Operating Reserve Market
  o SPP has also taken on the responsibility of being the consolidated Balancing Authority.

• Overall, the Integrated Marketplace has performed well.
  o Load is being served with fewer resources online.
  o Prices are consistent with historical prices in relation to gas costs.
  o Congestion patterns have remained consistent from the EIS market to the Integrated Marketplace.

• The price charts with average LMP for load-serving entities in Section 1 have been expanded to include prices for both the Day-Ahead Market and the Real-Time Balancing Market.
1.1 Day-Ahead and Real-Time Prices

- The following figure shows the Locational Marginal Price (LMP) for the Day-Ahead Market and the Real-Time Balancing Market. This is calculated by taking the simple average of LMP at the SPP North and SPP South hubs.
  - The LMP is made up of
    - Marginal Energy Component (MEC)
    - Marginal Congestion Component (MCC)
    - Marginal Loss Component (MLC)

- Overall, Day-Ahead and Real-Time prices were lower during the summer season than the spring.
  - This is partially explained by the extreme winter weather event experienced at the beginning of the spring season.
  - Higher spring prices can also be attributed to higher gas costs during those months.

- Prices increased steadily over the summer months as warmer weather took hold over the footprint, thus increasing demand.

- Monthly average Locational Imbalance Prices (LIP) from the SPP Energy Imbalance Service (EIS) market are shown for February 2014 and prior.
  - Although LIPs are not directly comparable to LMPs in the Integrated Marketplace, they do provide a frame of reference.
1.1 Day-Ahead and Real-Time Prices

**Day Ahead Prices**

<table>
<thead>
<tr>
<th>Month</th>
<th>DA MEC</th>
<th>DA MLC</th>
<th>DA MCC</th>
<th>DA LMP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jun 13</td>
<td>39.75</td>
<td>-0.08</td>
<td>0.15</td>
<td>39.82</td>
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<tr>
<td>Jul 13</td>
<td>39.24</td>
<td>-0.57</td>
<td>-2.97</td>
<td>35.70</td>
</tr>
<tr>
<td>Aug 13</td>
<td>37.13</td>
<td>-0.42</td>
<td>-1.13</td>
<td>35.58</td>
</tr>
<tr>
<td>Sep 13</td>
<td>33.14</td>
<td>-0.52</td>
<td>-1.37</td>
<td>31.24</td>
</tr>
<tr>
<td>Oct 13</td>
<td>32.71</td>
<td>-0.26</td>
<td>-0.67</td>
<td>31.78</td>
</tr>
<tr>
<td>Nov 13</td>
<td>34.18</td>
<td>-0.16</td>
<td>-1.10</td>
<td>32.92</td>
</tr>
<tr>
<td>Dec 13</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan 14</td>
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<tr>
<td>Feb 14</td>
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<tr>
<td>Mar 14</td>
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<tr>
<td>Apr 14</td>
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<tr>
<td>May 14</td>
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<tr>
<td>Jun 14</td>
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<td>Jul 14</td>
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<tr>
<td>Aug 14</td>
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<td></td>
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<td></td>
</tr>
</tbody>
</table>

**Real Time Prices**

<table>
<thead>
<tr>
<th>Month</th>
<th>RT MEC</th>
<th>RT MLC</th>
<th>RT MCC</th>
<th>RT LMP*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jun 13</td>
<td>40.40</td>
<td>-0.10</td>
<td>-1.60</td>
<td>25.35</td>
</tr>
<tr>
<td>Jul 13</td>
<td>33.88</td>
<td>-0.49</td>
<td>-3.80</td>
<td>26.95</td>
</tr>
<tr>
<td>Aug 13</td>
<td>37.92</td>
<td>-0.49</td>
<td>-3.80</td>
<td>26.95</td>
</tr>
<tr>
<td>Sep 13</td>
<td>28.91</td>
<td>-0.38</td>
<td>-3.80</td>
<td>27.92</td>
</tr>
<tr>
<td>Oct 13</td>
<td>31.22</td>
<td>-0.08</td>
<td>-3.80</td>
<td>30.84</td>
</tr>
<tr>
<td>Nov 13</td>
<td>33.55</td>
<td>-0.18</td>
<td>-3.80</td>
<td>30.84</td>
</tr>
<tr>
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<td>Apr 14</td>
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<td>May 14</td>
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<td>Jun 14</td>
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<tr>
<td>Jul 14</td>
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<tr>
<td>Aug 14</td>
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</tr>
</tbody>
</table>

**Notes:**
- **DA MEC** - Marginal Energy Component
- **DA MLC** - Marginal Loss Component
- **DA MCC** - Marginal Congestion Component
- **RT MEC** - Marginal Energy Component
- **RT MLC** - Marginal Loss Component
- **RT MCC** - Marginal Congestion Component
- **RT LMP** - Marginal Congestion Component
- **RT LMP prior to March 2014 is the average LIP (Locational Imbalance Price) from the Energy Imbalance Service (EIS) market**
1.2 Price Contour Maps

- The following price contour maps provide an overall picture of congestion and price patterns in the footprint.
  - Blue represents lower prices and red represents higher prices.
  - Significant color changes across the map signify constraints that limit the transmission of electricity from one area to another.
  - Some other factors that can influence congestion and resulting prices are generator and transmission outages, weather events, differences in fuel prices and differences in temperatures across the footprint.

- Overall, pricing patterns between Day-Ahead and Real-Time are similar.
  - Pricing patterns are similar to what has been observed in the EIS market, with less expensive generation in the north and wind generation in the west-central part of the footprint.
  - The southwestern corner of the footprint continues to experience the highest average prices in SPP.

- Maps for the summer period, as well as the six month prices, are shown.
1.2 Price Contour Maps

Day-Ahead (average June - August)

Real-Time (average June - August)
1.2 Price Contour Maps

Day-Ahead (average March - August)

Real-Time (average March - August)
The following figure shows the Day-Ahead to Real-Time price divergence at the SPP system level.

- Price divergence % is calculated as \(\frac{(RT \text{ Monthly Average LMP} / DA \text{ Monthly Average LMP}) - 1}{1}\), using system prices for each interval (RTBM) or hour (DAMKT).
- The divergence (absolute) is calculated by taking the absolute value of the divergence for each interval (RTBM) or hour (DAMKT).

The SPP Markets are experiencing some divergence between Day-Ahead and Real-Time.

- This price divergence can be at least partially explained by the significant price volatility in the Real-Time Market.
- Prices are expected to be more volatile in the Real-Time Balancing Market than the Day-Ahead Market.
1.3 Day-Ahead and Real-Time Price Divergence

**PRICES**

Divergence % is calculated as (RT LMP / DA LMP) - 1

<table>
<thead>
<tr>
<th>Date</th>
<th>DA LMP</th>
<th>RT LMP</th>
<th>Divergence %</th>
<th>Divergence (ABS)</th>
<th>Divergence % (ABS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jun 13</td>
<td>39.82</td>
<td>38.70</td>
<td>-6.7%</td>
<td>20.82</td>
<td>53.1%</td>
</tr>
<tr>
<td>Jul 13</td>
<td>35.70</td>
<td>29.59</td>
<td>-19.5%</td>
<td>13.69</td>
<td>43.1%</td>
</tr>
<tr>
<td>Aug 13</td>
<td>35.58</td>
<td>35.97</td>
<td>3.8%</td>
<td>13.54</td>
<td>40.3%</td>
</tr>
<tr>
<td>Sep 13</td>
<td>31.24</td>
<td>26.78</td>
<td>-15.6%</td>
<td>7.85</td>
<td>29.8%</td>
</tr>
<tr>
<td>Oct 13</td>
<td>31.78</td>
<td>29.93</td>
<td>-4.0%</td>
<td>8.15</td>
<td>25.4%</td>
</tr>
<tr>
<td>Nov 13</td>
<td>32.92</td>
<td>32.01</td>
<td>-3.6%</td>
<td>7.83</td>
<td>24.0%</td>
</tr>
</tbody>
</table>

*SPP State of the Market Report Summer 2014*
The next metric presents gas cost from the Panhandle Eastern Pipeline (PEPL) compared to electricity prices in the SPP footprint.

- Although the cost at PEPL is not an exact cost that may be experienced by a particular market participant or resource, the cost serves as a proxy for the overall gas costs experienced across the footprint.

- Historically gas prices and Real-Time prices have been highly correlated in SPP.
  - Workably competitive markets should experience highly correlated gas costs and energy prices in general.
  - Overall this trend has carried over from the EIS market into the Integrated Marketplace.
  - Although electricity prices and gas costs are highly correlated over time, some periods, especially summer months, experience divergence.
  - This pattern changed in May, when gas costs and LMP (both Day-Ahead and Real-Time) diverged.

- Gas costs were higher in summer 2014 compared to the same time period in 2013.
1.4 Electricity Prices and Gas Costs

<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>DA LMP</td>
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<td></td>
<td></td>
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<td></td>
<td>$39.82</td>
<td>$37.70</td>
<td>$35.58</td>
<td>$33.24</td>
<td>$31.78</td>
<td>$32.92</td>
</tr>
<tr>
<td>RT LMP</td>
<td>25.35</td>
<td>26.95</td>
<td>26.39</td>
<td>24.48</td>
<td>23.86</td>
<td>23.92</td>
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<td>35.97</td>
<td>26.78</td>
<td>29.93</td>
<td>32.01</td>
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<tr>
<td>Gas Cost</td>
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<td>3.47</td>
<td>3.23</td>
<td>3.43</td>
<td>3.51</td>
<td>3.41</td>
<td>4.22</td>
<td>4.83</td>
<td>8.00</td>
<td>5.17</td>
<td>4.44</td>
<td>4.37</td>
<td>4.38</td>
<td>3.88</td>
<td>3.77</td>
</tr>
</tbody>
</table>

*RT LMP prior to March 2014 is the average LIP (Locational Imbalance Price) from the Energy Imbalance Service (EIS) market.

Gas Cost is represented by cost at the Panhandle Eastern Pipeline.
• Pricing patterns in the Integrated Marketplace have generally stayed consistent with that experienced in the EIS Market.
  o The far southwest portion of the SPP footprint generally experiences the highest average prices.
  o Entities in Nebraska and the west central portion of the footprint generally experience the lowest average prices.
  o These differences are driven by congestion patterns and high levels of low-cost generation.

• Both Day-Ahead and Real-Time LMPs are shown on the summer and six month charts.

• For the summer period, the difference between the highest cost load area and the lowest cost load area expressed as a percent of system average price was 45%, similar to the 43% experienced in the spring.
1.5 Average LMP by Load-Serving Entity (June - August)

Average is for the period from June - August. Only load-serving entities are included.
Average is for the previous 6 months. Only load-serving entities are included.
• Volatility is represented using the coefficient of variation, which is the standard deviation divided by the mean for the period for each load-serving entity.

• Although overall volatility is higher than experienced in the EIS market, the relative patterns remain similar.
  o The entities in the northern portion of the footprint tend to experience the lowest average prices while they typically see the most volatility in pricing.
  o Some higher volatility in the Integrated Marketplace can be attributed to scarcity pricing.
Volatility is for the period from June - August. Only load-serving entities are included.
Volatility is for the previous 6 months. Only load-serving entities are included.
• The next figure shows monthly average Day-Ahead and Real-Time prices for the two Trading Hubs in SPP: the North and South hubs.
  o A trading hub is a settlement location consisting of an aggregation of price nodes developed for financial and trading purposes.

• Due to an abundance of lower-cost generation in the northern part of the SPP footprint, prices and the North Hub are consistently lower.

• The North Hub also shows a consistent day-ahead premium in price that is often experienced in other markets.
• The following figures show Marginal Clearing Prices (MCP) for ancillary services in the SPP Integrated Marketplace.
  o Regulation (up and down) is shown as an SPP average.
  o Reserves (spin and supplemental) are shown by reserve zones:
    ▪ Reserve Zone 1 – Nebraska
    ▪ Reserve Zone 2 – Western Kansas, Oklahoma panhandle, Texas panhandle
    ▪ Reserve Zone 3 – Western Texas (south of panhandle), Eastern New Mexico
    ▪ Reserve Zone 4 – Eastern Kansas, Missouri, Arkansas, Oklahoma (outside of panhandle), NE Texas, Louisiana

• With the extreme winter weather event on March 2 and 3, those dates experienced unusually high ancillary service prices, driving up the average cost for March above the months that followed.

• Reserve Zones 1 and 4 have identical values, so Zone 1 does not show up on the Spinning and Supplemental Reserves chart that follows.
1.8 Ancillary Service Prices - Regulation

PRICES

Regulation

$/MWh


Reg Down RT  Reg Up RT
* Reserve Zone 1 and Reserve Zone 4 have the same prices for both Spinning and Supplemental, therefore the line for Zone 1 is not visible.
2.1 Congestion by Shadow Price

- The impact of a constraint on the market can be illustrated by its shadow price, which reflects the intensity of congestion on the path represented by the flowgate.
  - The shadow price indicates the marginal value of an additional MW of relief on a constraint in reducing the total production costs.
  - The shadow price is also a key determinant in the Marginal Congestion Component of the LMP for each pricing point.

- As Figure 2.1 shows, the Integrated Marketplace has experienced similar congestion patterns as the EIS market.
  - The Texas Panhandle remains the most congested area with the Osage Switch - Canyon East flowgate experiencing the highest shadow prices in both DA and RT. Limited import capability and low cost generation north of the constraint are key factors driving this congestion.
  - The Woodward – FPL Switch flowgate has experienced congestion due to the different parts of the new Tuco-Woodward 345kV line being energized as the project is completed. A portion was energized on 5/1, while remainder of the line was energized on 9/26.

- Other areas also experience congestion, which can be caused by many factors, including transmission and generation outages (planned or unplanned), weather events, and external impacts.

- Figure 2.2 shows Real-Time congestion by shadow price for the previous twelve months and includes projects that may provide relief to these congested flowgates.
### 2.1 Congestion by Shadow Price (June - August)

<table>
<thead>
<tr>
<th>Flowgate Name</th>
<th>Region</th>
<th>Flowgate Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>OSGCANBUSDEA</td>
<td>Texas Panhandle</td>
<td>Osage Switch - Canyon East (115) ftlo Bushland - Deaf Smith (230) [SPS]</td>
</tr>
<tr>
<td>WDFPPLWDWTAT</td>
<td>Western Oklahoma</td>
<td>Woodward - FPL Switch (138) ftlo Woodward EHV - Tatonga (345) [OGE]</td>
</tr>
<tr>
<td>TEMP67_20472</td>
<td>North Central Oklahoma</td>
<td>Renfrow (138) ftlo Hunter - Woodring (345) [OGE]</td>
</tr>
<tr>
<td>TEMP38_20360</td>
<td>South Central Kansas</td>
<td>Sun City - Medicine Lodge (115) ftlo Finney - Hitchland (345) [SECI]</td>
</tr>
<tr>
<td>SHAHAYKNOXFR</td>
<td>Central Kansas</td>
<td>South Hays - Hays (115) ftlo Knoll Xfmr (230/115) [MIDW]</td>
</tr>
<tr>
<td>TEMPT2_20480</td>
<td>Eastern Kansas</td>
<td>Wakarusa Jct. - SW Lawrence (115) ftlo Bismark Jct. - Farmers Consumer Group (115) [WR]</td>
</tr>
<tr>
<td>GENTLMREDWIL</td>
<td>Western N-S Corridor</td>
<td>Gentleman - Red Willow (345) [NPPD]</td>
</tr>
<tr>
<td>REDWILLMINGO</td>
<td>Western N-S Corridor</td>
<td>Red Willow - Mingo (345) [NPPD-SECI]</td>
</tr>
<tr>
<td>TEMP50_20450</td>
<td>Western Nebraska</td>
<td>Ogallala - Brule (115) ftlo Stegall Xfmr (345/230) [NPPD]</td>
</tr>
<tr>
<td>TEMP48_20358</td>
<td>NW Louisiana</td>
<td>Longwood - Oak Pan-Harr (138) ftlo SW Shreveport Xfmr (345/138) [AEP]</td>
</tr>
</tbody>
</table>
2.2 Congestion by Shadow Price (12 month)

**CONGESTION**

Contains data from last six months of EIS market and first six months of Integrated Marketplace.
In order to show twelve months of data, only real-time is included for the Integrated Marketplace.

<table>
<thead>
<tr>
<th>Flowgate Name</th>
<th>Region</th>
<th>Flowgate Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>OSGCANBUSDEA</td>
<td>Texas Panhandle</td>
<td>Osage Switch - Canyon East (115) ftlo Bushland - Deaf Smith (230) [SPS]</td>
</tr>
<tr>
<td>WDWPLWDWTAT</td>
<td>Western Oklahoma</td>
<td>Woodward - FPL Switch (138) ftlo Woodward EHV - Tatonga (345) [OGE]</td>
</tr>
<tr>
<td>EASXFEASTJ</td>
<td>KC - Omaha Corridor</td>
<td>Eastown Xfmr (345/161) ftlo Eastown - St. Joe (345) [GMOC]</td>
</tr>
<tr>
<td>VICXFMRWAYSTE</td>
<td>Western Nebraska</td>
<td>Victory Hill Xfmr (230/115) ftlo Wayside - Stegall (345) [NPPD-WAUE]</td>
</tr>
<tr>
<td>PENMUNSCRCRA</td>
<td>KC - Omaha Corridor</td>
<td>Pentagon - Mund (115) ftlo 87th Street - Craig (345) [WR]</td>
</tr>
<tr>
<td>NEORINOBLC</td>
<td>SE Kansas</td>
<td>Neosho - Riverton (161) ftlo Neosho - Blackberry (345) [WR-EDE-AECI]</td>
</tr>
<tr>
<td>IATSTJFHCW</td>
<td>KC - Omaha Corridor</td>
<td>Iatan - Stranger Creek (345) ftlo St. Joe - Hawthorn (345) [KCPL-WR-GMOC]</td>
</tr>
<tr>
<td>HAYVINOSKNO</td>
<td>Central Kansas</td>
<td>Hays - Vine (115) ftlo Post Rock - Knoll (230) [MIDW]</td>
</tr>
<tr>
<td>SUBTEKFTCRAU</td>
<td>KC - Omaha Corridor</td>
<td>Sub 1226 - Tekamo (161) ftlo Fort Calhoun - Raun (345) [OPPD-MEC]</td>
</tr>
<tr>
<td>SHAHXFLEUKTR</td>
<td>Texas Panhandle</td>
<td>Shamrock Xfmr (115/69) ftlo Tuco - Oklaunion (345) [AEP-SPS]</td>
</tr>
</tbody>
</table>

* Reciprocally Coordinated Flowgate with MISO

In order to show twelve months of data, only real-time is included for the Integrated Marketplace.

**Flowgate Name**

- **OSGCANBUSDEA**: Texas Panhandle
- **WDWPLWDWTAT**: Western Oklahoma
- **EASXFEASTJ**: KC - Omaha Corridor
- **VICXFMRWAYSTE**: Western Nebraska
- **PENMUNSCRCRA**: KC - Omaha Corridor
- **NEORINOBLC**: SE Kansas
- **IATSTJFHCW**: KC - Omaha Corridor
- **HAYVINOSKNO**: Central Kansas
- **SUBTEKFTCRAU**: KC - Omaha Corridor
- **SHAHXFLEUKTR**: Texas Panhandle

**Shadow Price ($/MWh)**

- OSGCANBUSDEA: $30
- WDWPLWDWTAT: $60
- EASXFEASTJ: $90
- VICXFMRWAYSTE: $60
- PENMUNSCRCRA: $30
- NEORINOBLC: $0
- IATSTJFHCW: $90
- HAYVINOSKNO: $30
- SUBTEKFTCRAU: $60
- SHAHXFLEUKTR: $0

**% Breached**

- OSGCANBUSDEA: 0%
- WDWPLWDWTAT: 3%
- EASXFEASTJ: 6%
- VICXFMRWAYSTE: 9%
- PENMUNSCRCRA: 6%
- NEORINOBLC: 3%
- IATSTJFHCW: 9%
- HAYVINOSKNO: 6%
- SUBTEKFTCRAU: 3%
- SHAHXFLEUKTR: 0%

*SPP State of the Market Report
Summer 2014*
## 2.2 Congestion by Shadow Price (12 month)

<table>
<thead>
<tr>
<th>Flowgate Name</th>
<th>Region</th>
<th>Location</th>
<th>Projects that may provide mitigation</th>
</tr>
</thead>
<tbody>
<tr>
<td>OSGCANBUSDEA</td>
<td>Texas Panhandle</td>
<td>Osage Switch - Canyon East (115) ftlo Bushland - Deaf Smith (230) [SPS]</td>
<td>Canyon East Sub –Randall County Interchange 115 kV line (June 2017 – Aggregate Studies)</td>
</tr>
<tr>
<td>SHAXFRTUCOKU</td>
<td></td>
<td>Shamrock Xfmr (115/69) ftlo Tuco - Oklaunion (345) [AEP-SPS]</td>
<td>No projects identified at time of report publication.</td>
</tr>
<tr>
<td>WDFPLWDWTAT</td>
<td>Western Oklahoma</td>
<td>Woodward - FPL Switch (138) ftlo Woodward EHV - Tatonga (345) [OGE]</td>
<td>Woodward – Tatonga ck2 345 kV (ITP10)</td>
</tr>
<tr>
<td>EASXFREASSTJ</td>
<td></td>
<td>Eastown Xfmr (345/161) ftlo Eastown - St. Joe (345) [GMOC]</td>
<td>Iatan – Nashua 345 kV Ckt 1 and Nahua 345/161 kV transformer Ckt 1 (June 2015 – Balanced Portfolio)</td>
</tr>
<tr>
<td>PENMUN87CRA</td>
<td>KC - Omaha Corridor</td>
<td>Pentagon - Mund (115) ftlo 87th Street - Craig (345) [WR]</td>
<td>Iatan – Nashua 345 kV Ckt 1 and Nahua 345/161 kV transformer Ckt 1 (June 2015 – Balanced Portfolio)</td>
</tr>
<tr>
<td>IATSTRTJHAW*</td>
<td></td>
<td>Iatan - Stranger Creek (345) ftlo St. Joe - Hawthorn (345) [KCPL-WR-GMOC]</td>
<td>Sibley – Mullin Creek 345 kV (June 2017 – High Priority)</td>
</tr>
<tr>
<td>SUBTEKFTCRAU*</td>
<td></td>
<td>Sub 1226 - Tekamo (161) ftlo Fort Calhoun - Raun (345) [OPPD-MEC]</td>
<td>Sibley – Mullin Creek 345 kV (June 2017 – High Priority)</td>
</tr>
<tr>
<td>VICXFRWAYSTE</td>
<td>Western Nebraska</td>
<td>Victory Hill Xfmr (230/115) ftlo Wayside - Stegall (345) [NPPD-WAUE]</td>
<td>Stegall 345/115 kV transformer Ckt 1 and Scottsbluff – Stegall 115 kV Ckt 1 (June 2017 – Regional Reliability)</td>
</tr>
<tr>
<td>NEORIVNEOBLC</td>
<td>SE Kansas</td>
<td>Neosho - Riverton (161) ftlo Neosho - Blackberry (345) [WR-EDE-AECI]</td>
<td>Kings River – Shipe Road 345 kV (Aggregate Studies)</td>
</tr>
<tr>
<td>HAYVINPOSNKO</td>
<td>Central Kansas</td>
<td>Hays - Vine (115) ftlo Post Rock - Knoll (230) [MIDW]</td>
<td>Hays Plant – South Hays 115 kV Ckt 1 (June 2016 – Regional Reliability)</td>
</tr>
</tbody>
</table>

* Reciprocally Coordinated Flowgate with MISO
2.3 Congestion by Interval

- One way to analyze transmission congestion is to study the total incidence of intervals in which a flowgate was either breached or binding.
  - A breached condition is one in which the load on the flowgate exceeds the effective limit.
  - A binding flowgate is one in which flow over the element has reached but not exceeded its effective limit.

- Figure 2.3, Congestion by Interval, shows the percent of intervals by month that had at least one breach, had only binding flowgates (but no breaches), or had no flowgates that were breached or binding (uncongested).

- Real-Time intervals of breached and binding flowgates in the Integrated Marketplace appear to be in line with historical trends.
  - Issues driving this increase include increasing wind generation online, outages related to transmission upgrades and unaccounted flows from adjacent systems.

- Note that the Summer Comparison figures represent June - August for each year.
  - The Real-Time Market seems to be experiencing an overall trend of increased breaches from 2012 to 2014.
2.3 Congestion by Interval

**Day Ahead**

- Uncongested Intervals
- Intervals with Binding Only
- Intervals with Breaches

**Real Time**

- Uncongested Intervals
- Intervals with Binding Only
- Intervals with Breaches

**SUMMER Comparison**

- Day Ahead
- Real Time

SPP State of the Market Report
Summer 2014
3.1 Generation by Fuel Type (Real-Time)

- Total monthly generation is shown, broken down by fuel type of resources.
  - Renewable included solar, biomass and other renewable resources (not including wind and hydro)
  - Other includes fuel oil and miscellaneous
  - Gas-CC represents natural gas combined-cycle units
  - Gas-SC includes all other natural gas simple-cycle units

- Monthly generation shown prior to March 2014 is from the SPP EIS market.

- Generation by wind as a percent of total generation has dropped off in the summer period, while gas generation (both combined-cycle and simple-cycle) has increased.

- Note that the Summer comparison figures represent June – August for each year.
3.1 Generation by Fuel Type (Real-Time)

**SUMMER Comparison**

**Generation (GWh)**

- **Other**
- **Gas-SC**
- **Gas-CC**
- **Coal**
- **Hydro**
- **Renewable**
- **Wind**
- **Nuclear**

**Average Monthly Generation (GW)**

- **2012**
- **2013**
- **2014**
3.1 Generation by Fuel Type by Percent (Real-Time)

**SUMMER Comparison**

- **Nuclear**
- **Wind**
- **Gas-CC**
- **Gas-SC**
- **Coal**

SPP State of the Market Report
Summer 2014
3.2 Wind Generation and Capacity Factor (Real-Time)

- The following figure shows wind generation and the wind capacity factor for the past 15 months.
  - Note that the wind capacity factor is not directly comparable between the EIS Market and the Integrated Marketplace because resources that were pseudo-tied out of SPP were removed from the capacity calculation beginning in March.

- Wind generation accounted for just over 9% of all generation for the Summer of 2014, compared to 13% in Summer 2013 and 5% in Summer 2012.

- Note that the Summer comparison figures represent June - August for each year.
### 3.2 Wind Generation and Capacity Factor (Real-Time)

**SUMMER Comparison**

- **Wind Generation**
- **Capacity Factor**

#### Wind Generation (Average Hourly Generation)

- **GW (Average Hourly Generation)**

#### Capacity Factor

- **% Total Generation**
- **Capacity Factor**

**SPP State of the Market Report**
Summer 2014
• The next figure shows the fuel types of marginal units in both the Real-Time Balancing Market and the Day-Ahead Market.
  o Marginal units set the Locational Marginal Price in each five minute interval.
  o During congested periods, the market is effectively segmented into several sub-areas, each with its own marginal resource.
  o During non-congested periods, one resource sets the price for the entire market, thus that resource is marginal for the interval.
  o When there is congestion, there can be more than one marginal unit during a five-minute interval.

• Gas-fired generators set prices in SPP the majority of the time in the Real-Time Balancing Market, and nearly 50% of the time in the Day-Ahead Market.

• In the Integrated Marketplace, wind resources are on the margin more than in the EIS Market. The “other” fuel type category, consisting primarily of oil-fired units, also shows up as being on the margin around 1-3% of all intervals.

• Note that the Summer comparison figures represent June-August for each year.
3.3 Fuel on the Margin (Day-Ahead) GENERATION

SUMMER Comparison

% Intervals on Margin

- Other
- Gas
- Coal
- Wind

SUMMER Comparison

% Intervals on Margin

- 2012
- 2013
- 2014

SPP State of the Market Report
Summer 2014
3.3 Fuel on the Margin (Real-Time) GENERATION

SUMMER Comparison

% Intervals on Margin

- Other
- Gas
- Coal
- Wind

SPP State of the Market Report
Summer 2014
• The following figure shows ramp available to the system as standardized by available capacity, compared to the average online capacity.
  o Ramp rates play a key role in Market operations because they place limits on how quickly a unit can respond to changes in loading conditions and the need for redispatch to manage congestion.

• The Ramp Availability Metric has been modified from the previous version. Previously online capacity was calculated using the nameplate capacity of resources, while currently the Economic Maximum (EcoMax) for resources is used in the calculation.

• Note that the Summer comparison figures represent June-August for each year.
3.4 Ramp Rate Availability (Real-Time)

**SUMMER Comparison**

- **MW Ramp Available per Minute**
- **MW/Min/100 MW online capacity**

SPP State of the Market Report
Summer 2014
3.5 Ramp Availability and Deficiency Intervals (Real-Time)

- The next figure shows the monthly average available ramp per interval along with the number of intervals with a ramp deficiency each month.
  - If ramp rates are too low, the market cannot respond quickly enough to manage system changes and ramp deficiencies will occur. Deficiencies result in price spikes that indicate a need for additional ramp.

- Note that the Summer comparison figures represent June-August for each year.
3.5 Ramp Availability and Deficiency Intervals (Real-Time)

**SUMMER Comparison**

- **Up Ramp Deficiency Intervals**
- **Down Ramp Deficiency Intervals**
- **MW Ramp Available per Minute**

**SUMMER**

- **Ramp Deficiency Intervals**
- **MW Ramp Available per Minute**

**SPP State of the Market Report Summer 2014**
3.6 Imports and Exports

- The following figure shows the average hourly (MW) for exports and imports for each month.

- Directly comparable data is not available prior to the start of the Integrated Marketplace on March 1, 2014.
### 3.6 Imports and Exports

**GENERATION**

**SUMMER Comparison**

- **MW (Average Hourly)**

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<td><strong>DA Exports</strong></td>
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<td><strong>RT Exports</strong></td>
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</table>

**MW (Average Hourly)**

- **2012**
- **2013**
- **2014**

**SPP State of the Market Report**

**Summer 2014**

**SUMMER Comparison**

- **MW (Average Hourly)**

<table>
<thead>
<tr>
<th></th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
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</thead>
<tbody>
<tr>
<td>MW (Average Hourly)</td>
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<td>0</td>
<td>2000</td>
</tr>
</tbody>
</table>

SPP State of the Market Report
Summer 2014
The next figure shows load scheduling for the peak hour.

- Under-scheduling load can cause SPP to commit more expensive peaking resources in real-time in order to satisfy load.
- Some real-time commitments may be made regardless of load scheduling due to the need to address reliability concerns, relieve local congestion or meet ramp demands.
- Over-scheduling load can suppress real-time price signals by overstating load.
- The calculation uses reported load from submitted meter data. This is a change from the Spring version of the report, where scheduled load was used.

The overall percentage of scheduling for the three month summer period was 101.6%, compared to 100.6% for the spring.
4.1 Day-Ahead Load Scheduling

UNIT COMMITMENT

SPRING Comparison

Day-Ahead Demand | Real-Time Obligation

GW

GW

SPP State of the Market Report
Summer 2014

44
• The next figure shows the Real-Time average hourly offered capacity for the peak hour.
  o Capacity above the line indicates that there is generally sufficient available capacity to meet peak load obligations.

• Although levels fluctuate from month to month, coal and gas resources typically account for 80-90% of offered capacity during peak hours.
• The following figure shows the Real-Time Average Peak Hour Capacity Overage.
  o SPP calculates the amount of capacity overage required for the Operating Day to ensure that unit commitment is sufficient to reliably serve load in Real-Time while maintaining the Operating Reserve requirements.
  o This is calculated as: Economic Maximum – Load – Net Scheduled Interchange – (Regulation Up + Spinning Reserves + Supplemental Reserves)

• Overall, average monthly peak hour capacity overage increased markedly for the summer months.
  o The spring overage averaged nearly 2,300 MW, while the summer average almost 3,500, representing a 54% increase from spring to summer.
4.3 Average Peak Hour Capacity Overage (Real-Time)  

UNIT COMMITMENT

Economic Maximum - Load - Net Scheduled Interchange - (Regulation Up + Spinning Reserves + Supplemental Reserves)
5.1 Virtual Transactions

- Virtual trading in the Day-Ahead Market facilitates convergence between the Day-Ahead and Real-Time prices.
  - Virtual trading helps improve the efficiency of the Day-Ahead Market and moderates market power.

- Virtual transactions scheduled in the Day-Ahead Market are settled in the Real-Time Market.
  - Virtual demand bids are profitable when the Real-Time energy price is higher than the Day-Ahead price.
  - Virtual supply offers are profitable when the Day-Ahead energy price is higher than the Real-Time price.

- The following figure shows cleared and uncleared virtual demand bids and supply offers.
  - Cleared demand bids have steadily increased each month.
  - Cleared supply offers have not shown any discernable trend to this point.
5.1 Virtual Transactions

Virtual trading in the Day-Ahead Market facilitates convergence between the Day-Ahead and Real-Time prices. Virtual demand bids are profitable when the Real-Time energy price is higher than the Day-Ahead price. Virtual supply offers are profitable when the Day-Ahead energy price is higher than the Real-Time price.

![Demand Bids Chart]

- Cleared Demand Bids
- Uncleared Demand Bids

![Supply Offers Chart]

- Cleared Supply Offers
- Uncleared Supply Offers

SPP State of the Market Report
Summer 2014
5.2 Cleared Virtual Transactions as Percentage of Reported Load

- Virtual trading in the Day-Ahead Market facilitates convergence between the Day-Ahead and Real-Time prices.
  - Cleared Virtual Bids as a percentage of Reported Load is averaging nearly 2.5% since the start of the Integrated Marketplace.
  - Cleared Virtual Offers as a percentage of Reported Load is averaging just about 4% since the start of the Integrated Marketplace.

- The SPP market has yet to meet the 10% level seen in other markets.
  - The average since the start of the Integrated Marketplace is right around 6%.
  - April had the largest amount of Virtual transactions at 8.6% of Reported Load.
5.2 Cleared Virtual Transactions as Percentage of Reported Load

Virtual trading in the Day-Ahead Market facilitates convergence between the Day-Ahead and Real-Time prices. Virtual demand bids are profitable when the Real-Time energy price is higher than the Day-Ahead price. Virtual supply offers are profitable when the Day-Ahead energy price is higher than the Real-Time price.
5.3 Virtual Transactions by Participant Type

- Virtual trading in the Day-Ahead Market facilitates convergence between the Day-Ahead and Real-Time prices.
  - Participants with physical assets (resources and/or load) often place transactions in order to hedge physical obligations.
  - In contrast, financial-only participants generally arbitrage prices.

- The vast majority of Virtual demand bids are placed by Financial Only participants.
5.3 Virtual Transactions by Participant Type

Virtual trading in the Day-Ahead Market facilitates convergence between the Day-Ahead and Real-Time prices. Virtual demand bids are profitable when the Real-Time energy price is higher than the Day-Ahead price. Virtual supply offers are profitable when the Day-Ahead energy price is higher than the Real-Time price.

**Demand Bids**

- Financial Only Owners Demand Bids
- Resource/Load Owner Demand Bids

**Supply Offers**

- Financial Only Owners Supply Offers
- Resource/Load Owner Supply Offers

SPP State of the Market Report
Summer 2014
• The next figure summarizes the monthly profitability of virtual demand bids and supply offers.

• Gross virtual profits for the first three months of the market totaled nearly $63 million, while gross virtual losses totaled just over $49 million.

• Since the start of the Integrated Marketplace, every month had a net profit from virtual transactions, with the exception of May, which had a net loss of just over $700,000.
5.4 Virtual Profits and Losses

Virtual trading in the Day-Ahead Market facilitates convergence between the Day-Ahead and Real-Time prices. Virtual demand bids are profitable when the Real-Time energy price is higher than the Day-Ahead price. Virtual supply offers are profitable when the Day-Ahead energy price is higher than the Real-Time price.
TCR/ARR funding is derived as follows:

1. Day-ahead revenue is collected daily
2. TCR holders are paid daily based on awarded TCR MW and Day-ahead clearing prices
   a. Uplift is charged daily
   b. Surpluses are redistributed Monthly and Annually
3. TCR revenue is collected daily based on TCR MW and TCR ACPs (consistent through month/season)
4. ARR holders are paid daily based on ARR MW and TCR ACPs (consistent through month/season)
   a. Uplift is charged daily
   b. Surpluses are redistributed Monthly and Annually
6.1 TCR Funding Summary

TRANSMISSION CONGESTION RIGHTS

Mar 14  Apr 14  May 14  Jun 14  Jul 14  Aug 14

DA Revenue  TCR Funding  TCR Uplift  Funding Percent  Cumulative Funding Percent

Millions

-10  0  10  20  30  40  50  60

-20%  0%  20%  40%  60%  80%  100%  120%

SPP State of the Market Report
Summer 2014
7.1 Make Whole Payments

- A Make Whole Payment is paid to a generator when the market commits a generator with offered costs exceeding the market revenue for the commitment period.
  - The Day-Ahead Make Whole Payment applies to commitments from the Day-Ahead Market.
  - The RUC Make Whole Payment applies to commitments made in the Day Ahead RUC and Intra-Day RUC processes.

- Day-Ahead Make Whole Payments are typically less frequent and lesser in magnitude than in the RUC Make Whole Payments in the Real-Time Market.

- In March, RUC Make Whole Payments were particularly high reaching almost $8 million due to an extreme winter weather event.

- As expected, the majority of the RUC Make Whole Payments are paid to gas resources.
7.1 Make Whole Payments

UPLIFT

Day-Ahead

RUC (Real-Time)
The Make Whole Payment Distribution Charge is applied to Asset Owners that receive benefits from units committed in the Day-Ahead and Real-Time Markets.

- The Day-Ahead Make Whole Payment Distribution Amount is an hourly charge or credit based on a daily allocation.
- The total of all Make Whole Payments paid to generation resources is spread among all Asset Owners according to the ratio of the load’s contribution relative to a specific market.
- For the Day-Ahead market, the distribution rate is the sum of all DA Market Make Whole Payments for the day, divided by the total DA Market withdrawals.
- For the Real-Time Market, the distribution rate is the sum of RT Make Whole Payments for the day divided by the total RT Market deviation.
7.2 Make Whole Payment - Distribution Rate

Day-Ahead

RUC

SPP State of the Market Report
Summer 2014
Each market participant with registered load is required to satisfy the must offer obligation for each asset owner associated with that registered load.

A market participant is in compliance if:
- The market participant has offered its available resources for an asset owner with a commitment status of Market, Self, or Reliability; or
- The market participant has net resource capacity for that asset owner greater than or equal to 90% of its load for that asset owner.

If a Market Participant is not in compliance with the must-offer obligation, it will be assessed a Day-Ahead Must-Offer (DAMO) penalty.
- The penalty amount is equal to the Day-Ahead Market LMP associated with the withheld capacity.
- When Must-Offer Penalty revenues are collected, the revenues are distributed to the Market Participants for an Asset Owner on a pro-rata basis for that Asset Owner's offered Resources. The Market Participant who failed the obligation does not receive a payment.

Note that in Figure 7.3, figures shown are from the most recent settlement statements available for that time period and are subject to resettlement.

Overall, the Day-Ahead Must-Offer failures have decreased, and they continue to represent a very small portion of the Day-Ahead Market.
7.3 Day-Ahead Must-Offer Penalty

$0, $60, $120, $180, $240

Jun 13, Jul 13, Aug 13, Sep 13, Oct 13, Nov 13, Dec 13, Jan 14, Feb 14, Mar 14, Apr 14, May 14, Jun 14, Jul 14, Aug 14
• Revenue Neutrality Uplift (RNU) ensures settlement payments/receipts for each hourly settlement interval equal zero.
  o Positive RNU - SPP receives insufficient revenue and collects from market participants.
  o Negative RNU - SPP receives excess revenue, which must be credited back to market participants.

• Revenue neutrality uplift is comprised by the following components:
  o DA Revenue Inadequacy
  o RT Revenue Inadequacy
  o RT Out of Merit Energy (OOME) Make Whole Payment
  o RT Regulation Deployment Adjustment
  o RT Joint Owned Asset (JOA) Adjustment
  o RT Inadvertent Interchange Adjustment
  o RT Congestion Adjustment

• Figures shown are from the most recent settlement statements available for that time period and are subject to change due to resettlement.
Figures prior to March 2014 are from the SPP EIS market and are shown here for comparison purposes.
### 7.4 Revenue Neutrality Uplift (RNU)

<table>
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<tbody>
<tr>
<td>DA Revenue Inadequacy</td>
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<td>-9</td>
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<td>-2</td>
<td>0</td>
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<tr>
<td>RT Revenue Inadequacy</td>
<td>-210</td>
<td>-75</td>
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<td>-54</td>
<td>-111</td>
<td>-49</td>
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<td>RT OOME MWP</td>
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<td>-97</td>
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<td>-173</td>
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<td>RT Regulation Deployment Adj</td>
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<tr>
<td>RT Congestion Adj</td>
<td>-353</td>
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<td>171</td>
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<td>SUBTOTAL</td>
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<td>-4,926</td>
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<td>Less RT Net Inadvertent Adj</td>
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*Figures prior to March 2014 are from the SPP EIS market and are shown here for comparison purposes.*
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<th>Acronym</th>
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<td>Auction Revenue Rights</td>
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