2015
Integrated Resource Plan
Filed in Compliance with 17.7.3 NMAC

Southwestern Public Service Company
July 16, 2015
Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond Southwestern Public Service Company’s, a New Mexico corporation (“SPS”) control, and many of which could have a significant impact on SPS’s operations, results of operations, and financial condition, and could cause actual results to differ materially from those anticipated. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.xcelenergy.com.

The information in this document is based on the best available information at the time of preparation. SPS undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, except to the extent the events or circumstances constitute material changes in the Integrated Resource Plan (“IRP”) that are required to be reported to the New Mexico Public Regulation Commission (“Commission”) pursuant to 17.7.3.10 NMAC.
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<td>MMBtu</td>
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<tr>
<td>MWh</td>
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<td>NAAQS</td>
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<td>NERC</td>
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<td>New Mexico and Texas</td>
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<td>NO$_2$</td>
<td>Nitrogen Dioxide</td>
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<td>Nitrous Oxide</td>
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<td>NPDES</td>
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<td>PPA</td>
<td>Purchased Power Agreement</td>
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<td>PSD</td>
<td>Prevention of Significant Deterioration</td>
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<td>RAVI</td>
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<td>TOU</td>
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<td>Micrograms per cubic meter</td>
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<td>U.S. Army Corps of Engineers</td>
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Section 1. EXECUTIVE SUMMARY

SPS, a wholly-owned subsidiary of Xcel Energy Inc. (“Xcel Energy”), presents its third integrated resource plan (“2015 IRP”) in accordance with the Efficient Use of Energy Act (NMSA 1978, § 62-17-1, et seq., “EUEA”) and 17.7.3 NMAC (the “IRP Rule”). SPS’s 2015 IRP: (i) identifies the most reasonable cost-effective resource portfolio to meet all applicable regulatory requirements and to supply the energy needs of New Mexico customers during the 2016-2035 Planning Period (“Planning Period”); and (ii) provides an Action Plan discussing 2015 IRP implementation from 2016–2019 (“Action Plan Period”).

SPS’s 2015 IRP was developed by considering studies, forecasts, regulatory predictions, and information exchanged through a public advisory process, combined with historical data, existing and potential resource capabilities, and costs associated with alternative generation resource expansion plans. SPS’s analysis considered both short- and long-term cost impacts to its customers, while balancing the ability to deliver the expected level of service to those customers and meeting applicable regulatory and operational obligations. The ultimate goal of SPS’s 2015 IRP was to develop a reliable, cost-effective, robust, and environmentally-focused generation expansion plan.

With respect to the Planning Period, the age of the SPS generation fleet, coupled with the proposed modifications to existing environmental regulations and proposed new environmental regulations, are the most significant drivers impacting the need for new generation. Based on SPS’s current generation retirement forecasts, the SPS resource need will increase by approximately 924 megawatts (“MW”) by 2025, climbing further to 3,551 MW by 2035. Most of the existing generation resources scheduled for retirement by 2035 are older natural gas generation units that are nearing the end of their useful life (some resources are already between 60 and 70 years old). And,
based on an initial review of the Environmental Protection Agency’s (“EPA”) proposed Clean Power Plan (“CPP”) Rule, implementing Section 111(d) of the Clean Air Act (“CAA”), at least half of the existing coal fleet (approximately 900 to 1,000 MW) could be subject to early retirement. Accordingly, the capacity need could rise to nearly 2,000 MW in 2025 and over 4,500 MW by 2035.

Taking into account the information known to SPS at this time, SPS’s preferred plan includes: (i) purchases of 140 MW of photovoltaic (“PV”) Solar (i.e., the NextEra Long-Term Purchased Power Agreements (“PPA”) pending in Case No. 15-00083-UT) to be installed by no later than December 2016; (ii) and a large combustion turbine (“CT”) within the 2018-2020 timeframe. These resource additions will allow SPS to address near-term energy and capacity requirements while retaining the flexibility to respond to the many dynamics that could impact SPS’s existing generation portfolio and future resource needs in the outer years of the Planning Period (i.e., 2020-2035).

Unlike previous IRP filings, the context for the 2015 IRP filing is rather unique due to the rapid changes and uncertainty that exists within the electric power sector. For example, the EPA is expected to issue its CPP Rule in the next 60 to 90 days. Given this timing, SPS is not currently able to provide a detailed analysis of the potential impacts of such a significant new regulation at this time. In addition to the uncertainty surrounding the CPP Rule, many other factors are beyond the scope of the present IRP and will likely require updates to the Action Plan and will be the subject of future IRPs, including the 2018 and 2021 plans. These factors include: (i) revised and new environmental regulations (more stringent than existing requirements); (ii) the impacts of the Southwest Power Pool (“SPP”) Integrated Marketplace (“IM”) on costs, generation cycling,
planned generation retirement dates, and reserve margins; (iii) customer expectations; (iv) technological advances; (v) aquifer depletion at SPS’s Tolk Station; (vi) an aging generation fleet (mentioned briefly earlier); (vii) load growth variability; (viii) tax credits and incentives; (ix) gas price forecasts; and (x) Commission Rule 572 renewable portfolio standard (“RPS”) acquisitions. Each of these factors is discussed in more detail in the 2015 IRP.

Accordingly, as mentioned earlier, it is very likely that SPS will need to modify its Action Plan and there may be significant changes between the 2015 IRP and future IRPs. Most importantly, the resource plan is presented based on the best information available at the time, with recognition that SPS will have to be flexible in resource plan execution over the Action Plan and Planning Periods to: (1) address expected short-term resource needs; and (2) respond to the uncertainties associated with the expected long-term needs in the outer years of the Planning Period. SPS will continue to actively monitor developments in these areas. However, as presented, SPS’s 2015 IRP provides a well-rounded resource portfolio that addresses customer cost impacts, environmental impacts, operational issues, and complies with applicable regulatory requirements. Finally, SPS is not requesting approval of any new resources actuations in this proceeding.

The remainder of the IRP is organized as follows: (i) Section 2 provides a background; (ii) Section 3 discusses existing supply- and demand-side resources, including a discussion of pending and proposed environmental regulations, the impact of an aging generation fleet, and load variability; (iii) Section 4 provides SPS’s load forecast; (iv) Section 5 presents SPS’s L&R table for the Planning Period; (v) Section 6 identifies the resource options; (vi) Section 7 presents a determination of the most cost-effective resource portfolio and alternative portfolios; (vii) Section 8 discusses the public advisory process; and (viii) Section 9 presents SPS’s Action Plan.
Section 2. BACKGROUND

New Mexico adopted the requirement for a formal IRP process in 2005 with the passage of the EUEA,\(^1\) and in 2007 the Commission promulgated the IRP Rule. The objective of the IRP is to identify the most cost-effective portfolio of resources to supply the energy needs of customers while giving preference to resources that minimize environmental impacts whose costs and service quality are equivalent (17.7.3.6 NMAC).

Specifically the IRP Rule requires that affected utilities provide the following details (17.7.3.9(B) NMAC):

1. a description of existing electric supply-side and demand-side resources;
2. current load forecasts;
3. load and resource (“L&R”) tables;
4. identification of resource options;
5. a description of the resource and fuel diversity;
6. identification of critical facilities susceptible to supply-source or other failures;
7. a determination of the most cost-effective resource portfolio and alternative portfolios;
8. a description of the public advisory process;
9. an Action Plan; and
10. any other information that the utility finds may aid the Commission in reviewing the utility’s planning process.

Please refer to Appendix J for a table indicating where each of the rule requirements is met in this filing.

SPS filed its initial New Mexico IRP on July 16, 2009 (Case No. 09-00285-UT) and its second IRP on July 16, 2012 (Case No. 12-00298-UT); both IRPs were accepted by the Commission without modification. SPS’s present filing, the 2015 IRP, includes all of the required

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\(^1\) The EUEA was most recently amended in 2014.
components of the IRP Rule. In addition to the required components, SPS has provided additional information, particularly in relation to proposed modifications to existing environmental standards and proposed new environmental regulations (17.7.3.9(B)(10) NMAC).
Section 3. EXISTING SUPPLY-SIDE & DEMAND-SIDE RESOURCES

3.01 - SPS-Owned Resources

SPS owns a number of supply-side generation resources, located in both New Mexico and Texas, which serve its entire system. These resources had a 2014 summer generation peak capacity of 4,513 MW and were comprised of a mix of coal, gas steam units, and simple-cycle CT units. Of the steam units, Harrington and Tolk Stations are both coal-fired and last year totaled approximately 2,122 MW and the remainder, or 1,754 MW, was gas-fired. Total simple-cycle generation was 637 MW.

Historical cost information, location, net dependable capacity (MW), capital costs (net plant balance), fixed and variable operating and maintenance costs ("FOM" and "VOM"), fuel costs, and purchased power costs for calendar year 2014 are provided in Table 3-1.
3.02 - SPS-Purchased Power

In addition to SPS’s owned generation, SPS currently has long-term PPAs totaling 1,232 MW of firm generation capacity and purchases the energy output from renewable intermittent generation consisting of 1,050 MW of wind and 50 MW\textsubscript{AC} of solar. In 2016, SPS projects that it will have an additional 250 MW of wind interconnected to its transmission system. These
resources serve SPS’s entire system. Table 3-2 lists the capacity and expiration dates for each long-term PPAs under which SPS currently purchases capacity and/or energy.

**Table 3-2: PPA Capacity and Expiration Dates**

<table>
<thead>
<tr>
<th>Purchased Power Agreement</th>
<th>Capacity (MW)</th>
<th>Expiration Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lea Power Partners (Hobbs, NM)</td>
<td>532</td>
<td>2040</td>
</tr>
<tr>
<td>Blackhawk Plant (Borger, TX)</td>
<td>220</td>
<td>2023</td>
</tr>
<tr>
<td>Calpine 1 (Oneta)</td>
<td>200</td>
<td>2018</td>
</tr>
<tr>
<td>Calpine 2 (Oneta)</td>
<td>200</td>
<td>2019</td>
</tr>
<tr>
<td>City of Lubbock (Cooke)</td>
<td>72</td>
<td>2019</td>
</tr>
<tr>
<td>Sid Richardson/Huber</td>
<td>8</td>
<td>2020</td>
</tr>
<tr>
<td>White Deer Wind</td>
<td>80</td>
<td>2018</td>
</tr>
<tr>
<td>Caprock Wind</td>
<td>80</td>
<td>2020</td>
</tr>
<tr>
<td>Wildorado Wind</td>
<td>160</td>
<td>2026</td>
</tr>
<tr>
<td>San Juan (Padoma) Wind</td>
<td>120</td>
<td>2025</td>
</tr>
<tr>
<td>Spinning Spur Wind</td>
<td>161</td>
<td>2026</td>
</tr>
<tr>
<td>Palo Duro Wind</td>
<td>250</td>
<td>2034</td>
</tr>
<tr>
<td>Mammoth Plains Wind</td>
<td>199</td>
<td>2034</td>
</tr>
<tr>
<td>Roosevelt Wind</td>
<td>250</td>
<td>2034</td>
</tr>
<tr>
<td>Sun Edison Solar</td>
<td>50</td>
<td>2032</td>
</tr>
</tbody>
</table>

In addition, SPS historic cost (calendar year 2014) information regarding each of the PPAs is provided in Appendix A.

Figure 3F.1 below provides a pictorial depiction of the general location of the SPS generation fleet (owned and purchased).
3.03 - Wheeling Agreements

SPS does not purchase any capacity or energy under wheeling agreements with other utilities.

3.04 - Demand Side Resources

The IRP Rule specifically requests that the utilities detail their existing demand-side management (“DSM”) resources in their IRP filing and defines those resources as “energy efficiency and load management.” Energy efficiency (“EE”) is defined in the IRP Rule as “measures, including energy conservation measures, or programs that target consumer behavior,
equipment or devices to result in a decrease in consumption of electricity without reducing the amount or quality of energy services.” Load management (“LM”) is defined as “measures or programs that target equipment or devices to decrease peak electricity demand or shift demand from peak to off-peak periods.” SPS offers DSM resources in both New Mexico and Texas in accordance with state-specific rules and laws.²

**New Mexico DSM**

Under the EUEA, SPS is required to acquire cost-effective and achievable DSM to achieve no less than a 5 percent reduction in 2005 retail sales by 2014 and an 8 percent reduction in 2005 sales by 2020. SPS’s 2005 New Mexico retail sales were 3,750,469 megawatt-hour (“MWh”). To meet the EUEA requirements, SPS needed to achieve savings of 187,523,450 kilowatt-hours (“kWh”) by 2014 and needs to achieve savings of 300,037,520 kWh by 2020.

SPS must annually report its achieved levels for the previous calendar year and receive approval of its going-forward plans to continue towards its statutory goals. SPS’s 2014 EE and LM Plan was approved in Case No. 13-00286-UT on June 25, 2014.³ Currently, the Commission is evaluating SPS’s 2016 EE and LM Plan (Case No. 15-00119-UT). Previous plans were approved for calendar years 2008 – 2013 in Case Nos. 07-00376-UT, 08-00333-UT, 09-00352-UT, and 11-00400-UT, respectively. Table 3-3 below describes SPS’s EE achievements under the EUEA.

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² DSM costs are directly assigned by jurisdiction.

³ *In the Matter of Southwestern Public Service Company’s Application for Approval of its (A) 2014 Energy Efficiency and Load Management Plan and Associated Programs, (B) Request for Financial Incentives for 2013-2015; (C) Cost Recovery Tariff Rider, and (D) Request to Establish Lower Minimum Savings Requirements for 2014 under the Efficient Use of Energy Act, Case No. 13-00286-UT, Final Order Adopting Certification of Stipulation (Jun. 25, 2014) (SPS requested, and received Commission approval of, lower savings requirements for 2014 consistent with Section 62-17-5(H) of the EUEA).*
<table>
<thead>
<tr>
<th>Year</th>
<th>Customer kW Saved</th>
<th>Customer kWh Saved</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>256</td>
<td>3,355,020</td>
</tr>
<tr>
<td>2009</td>
<td>2,682</td>
<td>14,136,023</td>
</tr>
<tr>
<td>2010</td>
<td>5,718</td>
<td>23,230,535</td>
</tr>
<tr>
<td>2011</td>
<td>7,838</td>
<td>35,641,535</td>
</tr>
<tr>
<td>2012</td>
<td>7,406</td>
<td>33,336,151</td>
</tr>
<tr>
<td>2013</td>
<td>8,056</td>
<td>37,674,221</td>
</tr>
<tr>
<td>2014</td>
<td>8,873</td>
<td>30,492,802</td>
</tr>
</tbody>
</table>

At the time of this IRP filing, SPS is offering the following approved DSM programs to its New Mexico customers (designated by “EE” for energy efficiency and “LM” for load management). All of the EE and LM programs offered in 2015 are programs that continued from 2014.

Residential Segment:

- Energy Feedback Pilot (EE) – distributes educational materials to residential customers and uses communication strategies to create permanent reductions in energy consumption and better understanding of the benefits associated with EE programs.

- Evaporative Cooling Rebates (EE) – provides an incentive in the form of a cash rebate to SPS’s electric customers who purchase evaporative cooling equipment for residential use. Customers receive checks mailed to their homes; the rebate does not come in the form of a customer account credit.

- Home Energy Services (EE) – includes residential and low-income measures as well as a kit for low-income customers. This program provides incentives for the installation of a wide range of measures that reduce customer energy costs and reduce peak demand and/or save energy for existing single- and multi-family residential customers. Incentives are paid to third-party EE service providers on the basis of deemed savings, which are standardized savings values or formulas for a wide range of measures in representative building types.
The program includes attic insulation, air infiltration reduction, duct leakage repairs, and high efficiency central air conditioners. The kit includes the following measures:

- two (2) 13-Watt Compact Fluorescent Lamp (“CFL”) bulbs;
- two (2) 20-Watt CFL bulbs;
- high efficiency showerhead;
- kitchen aerator (1.5 gallons per minute (“gpm”); and
- bathroom aerator (1.0 gpm).

- Home Lighting & Recycling (EE) – offers discounts to motivate consumers to purchase energy efficient CFL bulbs and Light Emitting Diode (“LED”) bulbs for their homes, as well as convenient ways for them to recycle the CFLs on burnout.

- Refrigerator Recycling (EE) – provides rebates for customers to recycle primary and secondary refrigerators as well as freezers, usually located in a garage or basement and is available to all SPS New Mexico residential electric customers with qualifying units.

- Saver’s Switch® – Residential (LM) – offers bill credits as an incentive for residential customers to allow SPS to control operation of their central air conditioners and electric water heaters on days when the electricity system is approaching its peak.

- School Education Kits (EE) – is a package of EE classroom activities combined with projects for the home. Each participant receives an activity kit containing:
  - one CFL (13 Watt – 60 Watt Equivalent);
  - two CFLs (18 Watt – 75 Watt Equivalent);
  - one LED (11 Watt – 60 Watt Equivalent);
  - high efficiency showerhead (1.5 gpm);
  - kitchen aerator (1.5 gpm);
  - bathroom aerator (1.0 gpm);
  - furnace air filter alarm;
  - LED nightlight;
  - digital water/air thermometer;
  - toilet leak detector tablets; and
  - parent evaluation card.
Business Segment:
• Business Comprehensive Program, which is made up of the following components:
  o Computer Efficiency (EE) – offers upstream incentives to encourage manufacturers to build and sell higher efficiency computers and provides downstream rebates to customers who install desktop personal computer virtualization, which reduces energy usage by hosting multiple users on a single computer.
  o Cooling Efficiency (EE) – SPS’s Cooling Efficiency Program provides financial incentives for customers to purchase energy-efficient electric cooling equipment;
  o Custom Efficiency (EE) – offers rebates to reduce incremental project costs for customers who install energy efficient measures. Since energy applications and building systems can vary greatly by customer type, this Program provides rebates for business projects or process changes that are not covered by SPS’s prescriptive programs;
  o Large Customer Self-Direct (EE) – provides the opportunity for qualifying large customers to either self-direct their own EE projects or opt-out of the EE tariff rider if they can prove they have completed all cost-effective conservation. Self-direct participants of this program are also eligible for the other Business Segment programs;
  o Lighting Efficiency (EE) – offers rebates for customers to install more efficient lighting, or de-lamp, as needed;
  o Motor & Drive Efficiency (EE) – offers rebates to customers who install motors exceeding the National Electrical Manufacturers Association Premium Efficiency® motors standards and variable frequency drives in existing and new construction facilities;
  o Building Tune-up (EE) – is a study/implementation option designed to assist smaller business customers to improve the efficiency of existing building operations by identifying existing functional systems that can be “tuned up” to run as efficiently as possible through low- or no-cost improvements;
• Interruptible Credit Option (“ICO”) (LM) – offers significant savings opportunities for New Mexico business customers who will grant SPS the right to interrupt their electric demand at
any time throughout the year, and accept an interruption, when called, with either one hour or no notice before the interruption;

- Saver’s Switch for Business (LM) – offers bill credits as an incentive for commercial customers to allow SPS to control operation of their central air conditioners on days when the electricity system is approaching its peak.

Table 3-4 below shows the remaining life of DSM achievements made since EUEA program inception in 2008, using the Portfolio Effective Useful Lifetime method (energy savings provided in gigawatt-hours (“GWh”).

Table 3-4: Remaining Savings Provided by the 2008-2014 EE Programs

<table>
<thead>
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</thead>
<tbody>
<tr>
<td>2012</td>
<td>0.256</td>
<td>3.767</td>
<td>2.682</td>
<td>15.758</td>
<td>6.403</td>
<td>26.019</td>
<td>6.439</td>
<td>39.284</td>
<td>9.524</td>
<td>37.123</td>
<td>-</td>
<td>-</td>
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<td>-</td>
<td></td>
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<tr>
<td>2015</td>
<td>0.051</td>
<td>0.753</td>
<td>2.682</td>
<td>15.758</td>
<td>6.403</td>
<td>26.019</td>
<td>6.439</td>
<td>39.284</td>
<td>9.524</td>
<td>37.123</td>
<td>10.405</td>
<td>41.916</td>
<td>6.080</td>
<td>34.133</td>
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<tr>
<td>2020</td>
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<td>2021</td>
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</tbody>
</table>

4 This calculation method is consistent with the methodology proposed by the Commission’s Utility Division Staff in Case No. 09-00352-UT (see Staff Compliance Affidavit Regarding Decretal Paragraph “L” of the Certification of Stipulation Adopted by the Commission in its March 11, 2010 Final Order in this Proceeding, Oct. 19, 2010).
EE Goals through 2035

The following goals were developed in accordance with the EUEA to allow SPS to attain a reduction in its 2005 retail sales of 5 percent by 2014 and 8 percent by 2020, and further, to maintain the 8 percent reduction beyond 2020. Note that the EUEA neither requires nor establishes annual goals. Thus, the goals in Table 3-5 below are preliminary and subject to change in SPS’s annual EE and LM Plans.

Table 3-5: Proposed New Mexico DSM Goals at the Generator for the Planning Period

<table>
<thead>
<tr>
<th>Year</th>
<th>Demand Savings (MW)</th>
<th>Energy Savings (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>7.519</td>
<td>33.186</td>
</tr>
<tr>
<td>2016</td>
<td>7.159</td>
<td>32.928</td>
</tr>
<tr>
<td>2017-2035</td>
<td>4.626</td>
<td>26.847</td>
</tr>
</tbody>
</table>

Texas DSM Requirements

SPS offers DSM programs in its Texas service territory pursuant to the Public Utility Regulatory Act and P.U.C. SUBST. R. 25.181. These programs include standard offer programs for commercial and industrial, LM, residential, and low-income customers limited to customers receiving service at 69 kilovolts (“kV”) or less and all government customers. The following table shows SPS’s historic demand savings (in MW) and energy savings (in GWh) in its Texas service territory.
Table 3-6: SPS’s EE and LM Achievements - 2008 to 2014 in Texas

<table>
<thead>
<tr>
<th>Year</th>
<th>Customer Demand Savings (MW)</th>
<th>Customer Energy Savings (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>3.92</td>
<td>12.566</td>
</tr>
<tr>
<td>2009</td>
<td>2.70</td>
<td>10.271</td>
</tr>
<tr>
<td>2010</td>
<td>3.67</td>
<td>15.699</td>
</tr>
<tr>
<td>2011</td>
<td>3.88</td>
<td>13.821</td>
</tr>
<tr>
<td>2012</td>
<td>5.30</td>
<td>9.077</td>
</tr>
<tr>
<td>2013</td>
<td>5.10</td>
<td>7.950</td>
</tr>
<tr>
<td>2014</td>
<td>5.02</td>
<td>11.900</td>
</tr>
</tbody>
</table>

In addition, SPS offers residential and business Saver’s Switch and ICO LM programs (the savings are not included in the table above).

3.05 - Reserve Margin and Reserve Reliability Requirements

Electric System Reliability Councils

The reliability of the electrical system of North America is coordinated by the North American Electric Reliability Corporation (“NERC”). NERC is comprised of eight separate regional councils (see Figure 3F.2 below). Each council is responsible for defining specific reliability criteria for use by the member electric systems. SPS is a member of the SPP, which is one of the eight NERC regional councils established to promote the reliable operation of the interconnected bulk power system.
**SPP Integrated Market**

The SPP IM was launched in March 2014. SPP is now responsible for generation unit commitment and dispatch across the SPP footprint and the 16 balancing authorities (“BA”) were consolidated into one BA. Additionally, SPP administers both day-ahead markets and real-time balancing markets, including markets for generation reserves, regulation, and supplemental energy. Instead of each load serving entity (e.g., SPS) committing and dispatching its own generation resources to meet its own load requirements, unit commitment and economic dispatch are now
performed by the SPP. Current expectations and future requirements regarding market operations, locational generation dispatch, congestion, and losses will impact future transmission and generation planning/siting activities. Because the SPP IM has only been in operation for just over a year, cost and other data (including operational data) is limited. However, SPS has already noticed certain operational changes in the way SPS generation is being dispatched. Specifically, SPS gas steam power plants are now being cycled more frequently compared to operation prior to the SPP IM, which increases the operations and maintenance ("O&M") costs and could result in an earlier retirement than what is currently planned.

Reserves - Generally

Electric systems owners work to maintain service at all times to their firm customers. As a result, each system must maintain an adequate supply of electric generation that not only will meet the maximum demand of its customers (i.e., the "peak" demand) but also provide for unforeseen events (e.g., transmission line outages, power plant outages, etc.). To accomplish these objectives, electric systems acquire (through direct ownership or PPAs) and operate more generation capacity than is needed to meet peak demand. The additional generation, above what is needed to meet peak customer demand, is called reserve margin or reserves. Generally, there are two basic types of reserves: (i) Planning Reserves, which are the amount of installed capacity required in excess of annual peak firm demand, and (ii) Operating Reserves, which are the amount of generation capacity required in real-time, either with units carrying spinning reserves or in standby, capable of providing additional electric supply in order to meet real-time changes in load/demand and any unforeseen contingencies (e.g., transmission outage, gas supply disruptions, etc.).
From a long-term planning standpoint, SPS is currently required by the SPP to plan for a 12 percent capacity margin (or 13.6 percent planning reserves) (discussed in more detail in the next subsection). SPP resource adequacy is constantly under review and it is plausible that the current capacity margin could be reduced (below the current 12 percent requirement) as the SPP gains experience in the IM.

**SPP Capacity Reserve Requirements**

SPP has adopted a “Capacity Margin” criterion to ensure reliable electric service is provided to firm load customers. SPP requires that each load-serving member maintain a “Capacity Margin” of at least 12 percent\(^5\) (which corresponds to a 13.6 percent reserve margin). The Capacity Margin formula, as well as its relationship to the more commonly referred to “reserve margin,” is provided below:

\[
\text{Capacity Margin} \% = \frac{\text{Capacity Margin (MW)}}{\text{System Capacity (MW)}} \times 100 = 12\% \\
\text{Reserve Margin} \% = \frac{1}{(1-\text{Capacity Margin} \%)} - 1 \\
= \frac{1}{(1-0.12)} - 1 \\
= 0.1364 = 13.6\% \\
\text{Capacity Margin (MW)} = \text{Reserve Margin} \% \times \text{Firm Load} \]

**SPS Capacity Reserves**

The future resource needs of the SPS system are estimated by performing a comparison of SPS’s (base) peak demand forecast with the system capacity (i.e., “capacity balance”). Once these needs are identified, SPS develops a resource acquisition plan to acquire the necessary electrical

\(^5\) Load serving members comprised of at least 75 percent hydro-based generation have a minimum required capacity margin of nine percent.
generating capacity to meet its customers’ peak demand plus the 12 percent capacity margin (the 12 percent margin equates to a 13.6 percent reserve margin when multiplied by firm load). Based upon the actual Capacity Margin in any one year, additional generating capacity might be acquired through various methods, including construction of SPS-owned facilities and/or PPAs via competitive resource solicitations.

3.06 - Existing Transmission Capabilities

SPS, as a member of SPP, participates in several technical groups and committees. SPS is also a member of the North American Transmission Forum, a group that promotes sharing of technical solutions among members.

An analysis of the SPS transmission system is contained in the SPP Integrated Transmission Planning Near-Term study report, which is provided as Appendix B. This report discusses the performance of the SPS network and recommends new projects to improve the network performance.

A list of current projects SPS is constructing based on notifications to construct and generator interconnections is provided as Appendix C.

Transmission Import Rights

SPS has a total of 1,714 MW of transmission flow capability between the SPP transmission system and SPS. SPS’s use of these rights on a firm basis is more fully described below.

400 MW Import Path from the Tulsa, Oklahoma Area

SPS has two, 200 MW, network resources delivered from the LS Power Oneta combined cycle (“CC”) facility; one for the term of January 1, 2012 - December 31, 2018, the other for the term of June 1, 2014 - May 31, 2019.
210 MW Import Path from Colorado

SPS has 210 MW of network service rights to import power and energy from/through the Public Service Company of Colorado system.

50 MW Import from Western Farmers Electric Cooperative

As agent for the Farmers Electric Cooperative, Inc., Central Valley Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc. (collectively, “Eastside Cooperatives”), SPS holds firm network transmission rights to import up to 50 MW from Western Farmers Electric Cooperative, a generation and transmission cooperative located in Oklahoma. This resource represents part of the Eastside Cooperatives’ Phase 1 load reduction under their Replacement Power Sales Agreements with SPS. The term of this service began June 1, 2012 and continues for 30 years.

Additional 80 MW Import from Western Farmers Electric Cooperative

This resource represents the Eastside Cooperatives’ Phase 2 load reduction under their Replacement Power Sales Agreements with SPS. The term of this service begins June 1, 2017 and continues for 30 years.

101 MW Import from Elk City 2 Wind

As agent for the cities of Brownfield, Floydada, Tulia, and Lubbock, Texas served under the West Texas Municipal Power Agency (collectively, “WTMPA”), SPS holds the firm network transmission rights to import up to 101 MW from Elk City 2 Wind, located in Oklahoma. This resource represents part of the replacement power required to serve the WTMPA members upon termination of their full requirements contracts with SPS. The term of this service begins June 1, 2019 and continues for 13 years.
3.07 - Environmental Impacts of Existing Supply-Side Resources

17.7.3.9(C)(12) NMAC requires utilities to provide environmental impacts of existing supply-side resources, including the following information: (1) the percentage of kWh generated by each fuel type; (2) where feasible, the emission rates (critical pollutants and carbon dioxide and mercury) of each supply side-resource; and (3) to the extent feasible, the current water consumption rate of its supply-side resources. These requirements are addressed below.

Environmental leadership is at the core of business for Xcel Energy. Xcel Energy’s clean energy strategy is a comprehensive balanced approach that includes adding renewable energy to the system, increasing the size of its EE programs, and reducing emissions at its plants. Xcel Energy has been the leading wind energy provider for 11 years in a row according to the American Wind Energy Association and ranks in the top ten for solar capacity according to the Solar Electric Power Association. SPS has 1,050 MW of wind under long-term PPAs and 472.7 MW of qualifying facilities (“QF”) wind, which have served to reduce customer rates in addition to meeting state-specific renewable requirements. Additionally, in New Mexico, SPS has a demonstration of four separate community solar projects installed on community partner sites in eastern and southeastern New Mexico, and has supported the installation of an additional 50 kW (“kilowatt”) system at Eastern New Mexico University-Roswell. In 2011, SPS began purchasing power from five 10 MW solar farms in Lea and Eddy Counties. Through its New Mexico Solar Rewards program, SPS currently provides incentives to customers interested in installing solar systems over 10 kW on homes and businesses; currently, there are over seventy customer-sited solar facilities connected to SPS’s system, with over 10 MWAC of solar capacity. Finally, SPS is currently seeking Commission approval of 140 MW of solar energy as economic system purchases in Case No. 15-00083-UT.
**Percentage of GWh Generated**

The percentages of GWh generated by each fuel used by SPS for Calendar Year 2014 are provided in Figure 3F.3 below.

**Figure 3F.3: Percentage in 2014 by Fuel Type**

![](image)

**SPS Emissions Information**

The emission rates for SPS-owned generation resources are shown in Table 3-7 below. All emission rates are expressed in pounds per kWh.

**Water Consumption Rates**

Average water consumption rates, by plant, and expressed in gallons per kWh (“H₂O Consumption”) are also shown in Table 3-7 below.
Table 3-7: Emission and Water Consumption Rates

<table>
<thead>
<tr>
<th>Plant</th>
<th>Unit</th>
<th>SO2</th>
<th>NOx</th>
<th>Particulate Matter</th>
<th>CO2</th>
<th>Hg</th>
<th>CO</th>
<th>Pb</th>
<th>VOC</th>
<th>H2O Consumption (Plant Average)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maddox</td>
<td>1</td>
<td>6.486E-06</td>
<td>1.683E-03</td>
<td>7.930E-05</td>
<td>1.29</td>
<td>2.703E-09</td>
<td>2.495E-04</td>
<td>2.703E-09</td>
<td>5.711E-05</td>
<td>1.20</td>
</tr>
<tr>
<td>Maddox</td>
<td>2</td>
<td>5.319E-06</td>
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3.08 - New and Future Environmental Regulations

The discussion below summarizes the complex array of existing and pending environmental mandates SPS must comply with. As will be seen, the discussion serves to highlight areas of uncertainty regarding rule promulgation or changes, and long-term planning changes that exist where SPS must make decisions with incomplete information regarding the evolution of future environmental regulations. Figure 3F.4 below illustrates the array of environmental regulations recently adopted or in development that may affect SPS-owned generation facilities.
Figure 3F.4: Reasonably Foreseeable Environmental Regulations
Status of Each Regulation

This section summarizes the current status and remaining unknowns about each regulation (identified earlier), along with the potential impacts on SPS’s generation resources.

A. Greenhouse Gas (“GHG”) Emissions from New and Existing Power Plants

The EPA began pursuing the regulation of GHG emissions as a result of the U.S. Supreme Court’s 2007 finding in Massachusetts v. EPA that GHGs are “air pollutants” that can be regulated under the CAA.6 In 2009, the EPA issued its “endangerment” finding that GHG concentrations in the atmosphere pose a threat to public health and welfare, and its “cause or contribute” finding that GHG emissions from motor vehicles contribute to these GHG concentrations.7

Whether or not the EPA would pursue regulation of GHGs under the CAA was, for a time, linked to the possible passage of national climate legislation. The U.S. House of Representatives passed an economy-wide GHG cap-and-trade bill in 2009, but similar legislation failed to pass the Senate. Other federal regulatory approaches – a carbon tax, national renewable portfolio standard, or clean energy portfolio standard – have also been discussed, but none of these approaches appears likely to receive the necessary support for passage in the near term. In the absence of legislation, the EPA is moving forward with GHG regulation of power plants under the CAA. These new regulations will have to be reviewed and assessed in future resource plans along with the other new and proposed regulations associated with air, water, and waste medias (discussed later).

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7 See http://epa.gov/climatechange/endangerment.
GHG Permitting

The EPA adopted permitting requirements for GHG emissions from new and modified large stationary sources that became effective in 2011. These permitting requirements, found under the New Source Review and Prevention of Significant Deterioration (“PSD”) sections of the CAA, are applied to new power plant construction or power plant modifications that increase GHG emissions above a certain threshold. In June 2014, the U.S. Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a GHG source is a major source required to obtain a PSD or operating permit; however, if a new or modified stationary source becomes subject to these permitting requirements by exceeding emission thresholds for other air pollutants (so called “anyway sources”), the EPA could continue to require the permitting process to evaluate the Best Available Control Technology (“BACT”) for GHG emissions. With respect to “anyway sources,” the EPA is continuing to apply its threshold that any new or modified source increasing its GHG emissions by more than 75,000 tons per year of carbon dioxide (“CO₂”) equivalents must evaluate BACT for GHGs in its permit application.

This GHG permitting program will be another limiting factor in obtaining air permits for new generation units by defining a set threshold for which major sources are permitted under CO₂. This was the defining factor for the original permit of operation for Jones 4. However, recent court rulings have made determinations regarding CO₂ emissions as the first of the limit factors which have allowed Jones 4 to mirror hours of operation to that of Jones 3.

GHG Emission Standards for New Power Plants

In June 2013, President Obama issued a Presidential Memorandum on Power Sector Carbon Pollution Standards, directing the EPA to use its authority under Section 111 of the CAA
to develop GHG emission standards for new and existing power plants. The memorandum directed
the EPA to issue proposed GHG emissions standards for new power plants under Section 111(b) of
the CAA by September 20, 2013. The EPA did so, and the proposed rule was published in the
Federal Register on January 8, 2014. The EPA is expected to finalize this rule in the fall of 2015.

The EPA’s proposed GHG New Source Performance Standard (“NSPS”) rule for
newly-constructed power plants would create two regulated source categories: (1) fossil fuel-fired
electric utility steam generating units and Integrated Gasification Combined Cycle (“IGCC”) units,
which are required to meet an emission performance standard of 1,100 pounds of CO₂ per MWh
(“lbs CO₂/MWh”); and (2) natural gas-fired stationary CTs, of which larger turbines are required to
meet a standard of 1,000 lbs CO₂/MWh and smaller turbines are required to meet a standard of
1,100 lbs CO₂/MWh. The proposed rule would effectively ban the construction of new coal power
plants unless they carbon capture and sequester (“CCS”) around half of their CO₂ emissions. Under
the proposed rule, NSPS would not apply to modified or reconstructed existing power plants. In
addition, installation of control equipment on existing plants would not constitute a “modification”
to those plants under the NSPS program.

While SPS disagrees with certain aspects of the proposed rule – including whether CCS
meets the statutory tests to qualify as the Best System of Emission Reduction (“BSER”) for new

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8 See http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-
pollution-standards.

9 Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric
Note that EPA released its first proposed New Source Performance Standard rule for GHG emissions from new sources in
April 2012. This proposal would have required any new fossil fuel-fired electric generating unit (EGU) source to meet
an emission performance standard of 1,000 lbs CO₂/MWh. The EPA has withdrawn that proposal and replaced it with
the January 2014 proposal described here.
coal units – it currently expects this rule to have limited effect on its resource planning. SPS does not currently plan to build any new coal-fired power plants, with or without CCS, and any new natural gas plants it may build will comply with the proposed NSPS for those units.

**GHG Emission Standards for Modified and Reconstructed Power Plants**

In June 2014, the EPA published a proposed NSPS rule under CAA Section 111(b) that would apply to GHG emissions from fossil fuel-fired utility boilers, IGCC units, and natural gas-fired stationary CTs that are modified or reconstructed. Under the proposed rule, a modification is defined as a change to an existing source that increases the source’s maximum achievable hourly rate of emissions and a reconstruction is defined as the replacement of components such that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable unit. Comments on this rule were due to the EPA on October 16, 2014, and a final rule is expected in the third quarter of 2015.

The proposed standards are not based on, and would not require, the installation of CCS technology. Instead, the proposed standard for fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) would require a combination of best operating practices and equipment upgrades. Modified sources would be required to meet a unit-specific emission limit determined by the unit’s best historical annual CO₂ emission rate (from 2002 to the date of the modification) plus an additional two percent emission reduction. In a second, “co-proposed” rule alternative, sources that are modified after becoming subject to a CAA Section 111(d) would be

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required to meet a unit-specific emission limit determined by the CAA Section 111(b) implementing authority based on the results of an EE improvement audit.

The proposal for gas-fired power plants would require emission standards based on efficient CC technology. Modified sources with heat input greater than 850 Million British Thermal Units (“MMBtu”)/hour (“hr”) (MMBtu/hr”) would be required to meet an emission rate limit of 1,000 lbs CO\textsubscript{2}/MWh-gross; modified sources with heat input less than or equal to 850 MMBtu/hr would be required to meet an emission rate limit of 1,100 lbs CO\textsubscript{2}/MWh-gross. The proposed rule would require that all existing sources that are modified or reconstructed after they are already subject to a CAA Section 111(d) existing source or CPP Rule plan must remain in the CPP Rule plan as existing sources, and remain subject to any applicable regulatory requirements in that plan, in addition to being subject to regulatory requirements under CAA Section 111(b). This position has been challenged as contrary to the CAA, under which a source can be regulated under either CAA Section 111(b) or the CPP Rule, but not both. In addition, a source that makes heat rate improvements for CAA Section 111(d) compliance, reduces its overall generation, or becomes load-following due to greater natural gas and renewable generation envisioned in the EPA’s CAA Section 111(d) plan, will have more difficulty meeting the emission standards included in the modified and reconstructed source proposal.

At this time, given that the rule is not finalized, it is not possible to evaluate the impact of these proposed standards on SPS’s resource planning. In addition, these requirements, once adopted, would only apply to future changes at SPS power plants if the company undertakes actions meeting the definitions of modification or reconstruction.
GHG Emission Standards for Existing Power Plants

The June 2013 Presidential Memorandum on Power Sector Carbon Pollution Standards directed the EPA to issue a proposed GHG emission standard for existing power plants under CAA Section 111(d) by June 1, 2014. The EPA released its proposed CPP Rule in June 2014. Comments were due December 1, 2014. The final rule is expected from EPA in August 2015. The impacts outlined below may change depending on any changes EPA finalizes in its rule.

The rule requires states to develop plans to reduce GHG emissions from existing power plants. EPA estimates that, under the proposed plan, the nation will reduce emissions of CO₂ from its fleet of existing plants by 25 percent by 2020 and 30 percent by 2030 from 2005 levels. However, state-by-state targets established under the rule vary based on the mix and efficiency of fossil generation within the state, the ability to redispatch coal to gas-fired generation, renewable energy potential, and energy efficiency and conservation opportunities. Some of the proposed targets are aggressive, with some states required to reduce by more than 30 percent. Also, the rule places the highest burdens on states with significant natural gas CC resources and the least burden on states that are predominantly coal based. SPS is concerned that the rule does not give credit to actions taken prior to 2012. Although SPS has implemented significant clean energy programs that have reduced emissions over the last decade, its customers may not realize value for these actions based on the proposed rule. The rule provides several different compliance pathways that states may choose to incorporate into state plans. It will take significant time to determine compliance.

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The next step after the final rule is the state plan process. States have to develop compliance plans to implement the rule, and impacts to SPS are affected by that process. State plans would be submitted in 2016, though some states may take a federal compliance plan, which EPA has yet to propose.

Unlike the new source rule under CAA Section 111(b), Section 111(d) of the CAA does not give the EPA authority to impose a uniform national emissions performance standard for existing power plants. Rather, the CAA directs the EPA to create a procedure for states to establish performance standards and design plans to achieve emission reduction goals. The EPA retains “backstop” authority to enforce state plans if states fail to do so and to impose a federal plan to force compliance if a state fails to submit an acceptable plan. The proposed rule has two main components:

- CO₂ intensity goals for each state, based on EPA’s view of the BSER for that state’s power sector; and
- Guidance to states for drafting plans to implement the rule.

The proposed rule includes CO₂ emission rate goals (lbs CO₂/MWh) for each state that must be achieved across the electricity system in the state, including an Interim Goal to be achieved on average over the years 2020-2029 and a final goal to be achieved in the year 2030 and thereafter. Rather than employing a traditional CAA approach based on emission controls that can be implemented at individual power plants or “inside the fence line,” the EPA has proposed goals based on a BSER that is applied to the electricity system statewide, including both regulated power plants (“affected Electric Generating Units (“EGU”)” in the rule) and activities outside the EPA’s CAA jurisdiction such as renewable and nuclear energy, EE, and the re-dispatch of generation from higher to lower CO₂-emitting facilities. The EPA’s authority to include these “beyond the fence
line” activities in its BSER has been questioned, and will likely be one of several areas of legal challenge once the final rule is published.

The proposed rule calculates the state goals by beginning with 2012 emissions and generation from fossil generating units within the state, then sequentially applying the following four emissions reduction “building blocks”:

1. Improving coal plant efficiency (heat rate) by 6 percent;
2. Increasing utilization of natural gas CC plants to a 70 percent capacity factor, displacing generation from coal and oil/gas steam units;
3. Increasing renewable energy and maintaining nuclear plants; and
4. Expanding DSM and EE measures based on national “best practice” levels.

The resulting lbs CO₂/MWh rate, with all four building blocks, is calculated as:

\[
\frac{2012 \text{ FOSSIL EMISSIONS}}{(\text{COAL+NGCC+RENEWABLE+NUCLEAR}) \text{ GENERATION} + \text{DSM}} = \text{STATE GOAL}
\]

This goal, or its equivalent in mass terms, must be met at the statewide level, on average from 2020-2029 (for the Interim Goal) and by 2030 (for the Final Goal). The EPA’s goal-setting method creates a wide disparity in reduction requirements — from 11 percent to 72 percent below the 2012 emission rate calculated by the EPA — across the country. Table 3-8 below shows the interim and final goals for the states in which SPS operates.

Table 3-8: Interim/Final Goals for SPS Area - EPA’s Proposed CAA Section 111(d) Rule

<table>
<thead>
<tr>
<th>State</th>
<th>2012 Rate (lbs CO₂/MWh)</th>
<th>Interim Goal (lbs CO₂/MWh)</th>
<th>Final Goal (lbs CO₂/MWh)</th>
<th>Reduction from 2012 Rate (%)</th>
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<tr>
<td>NM</td>
<td>1,586</td>
<td>1,107</td>
<td>1,048</td>
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<td>TX</td>
<td>1,284</td>
<td>853</td>
<td>791</td>
<td>38%</td>
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The proposed rule requires states to propose to the EPA plans for achieving their emission reduction goals. States are provided some flexibility in achieving these goals. They may use:

- Different combinations of the four building blocks used in setting the goals (i.e., less of one building block compensated by more of another);
- Emission reduction measures not considered by the EPA in setting the goals, including but not limited to: retirement of coal plants; transmission and distribution efficiency improvements, biomass co-firing, gas co-firing, inclusion of new NGCC units in the state’s plan, CCS retrofits on existing coal plants, adding concentrating solar power (“CSP”) to the steam cycle of fossil plants, heat rate improvements on gas or oil plants, nuclear uprates, new coal or gas plants going beyond 111(b) requirements (e.g., credit for doing more CCS than required to reach 1,100 lb/MWh NSPS on new coal), CCS on new gas plants, energy storage reducing the amount of fossil generation needed to balance intermittent renewables, industrial combined heat and power, and possibly out-of-sector GHG offsets;\(^\text{13}\)
- The option to convert the rate-based goals into a statewide mass budget;
- The option to take a multi-state or regional approach, collaborating with other states to design a compliance plan that achieves the rate- or mass-based targets across participating states; and/or
- The option to implement cap-and-trade or carbon-pricing programs, or other types of trading.

Any CO\(_2\) reduction measures are approvable as long as they achieve the required emission reductions by the required date; create enforceable limits for affected EGUs; and are quantifiable, enforceable, and non-duplicative (i.e., avoid double-counting of emission reductions).

State plans are due to the EPA one year after the final rule, or 2016; states may apply for a one-year extension to June 2017 or a two-year extension to 2018 if they are collaborating on a

\(^{13}\) The proposed rule is ambiguous on whether out-of-sector GHG offsets would be allowed to be included in state plans. Offsets may be allowed as long as a state can still demonstrate the required level of reductions from affected EGUs.
multi-state implementation plan. The EPA aims to approve state plans within one year after receiving them. Compliance would effectively begin in 2020 (with the first required report due in 2022, on the 2020 results). The interim goals are binding and states must show that they are on track to meet the interim goal on average by 2029. From the year 2030 and on, compliance is demonstrated based on a rolling three-year timeframe.

Table 3-9 below summarizes the anticipated timeline of GHG rules. Note that litigation could delay the timelines below.

Table 3-9: Estimated GHG Regulatory Timeline

<table>
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<th>Action</th>
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<tr>
<td>EPA finalized new source GHG rule</td>
<td>January 2015</td>
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<tr>
<td>EPA finalizes modified/existing source GHG rule</td>
<td>August 2015</td>
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<tr>
<td>EPA finalizes existing source GHG rule</td>
<td>August 2015</td>
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<tr>
<td>Existing source rule state plans submitted to EPA</td>
<td>June 2016 – June 2018</td>
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<tr>
<td>EPA approval of existing source rule state plans</td>
<td>One year after submission</td>
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<tr>
<td>Compliance begins</td>
<td>2020</td>
</tr>
<tr>
<td>Reporting begins</td>
<td>2022</td>
</tr>
<tr>
<td>Final Goal must be achieved</td>
<td>2030 on, with 3-year rolling compliance reporting</td>
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While the final environmental outcome of the CPP Rule remains undefined, it is clear that the general direction is a more restrictive environmental focus. This new and restrictive focus could result in reduced coal operations and/or earlier retirement of coal generation and a greater reliance on natural gas-fired generation. Increased reliance on natural gas-fired generation generally increases portfolio volatility, due to the variable nature of natural gas prices. In addition, depending upon the cost effectiveness of renewables, some of the reductions in coal energy could be replaced with increased wind and/or solar generation (instead of increases in natural gas generation). Fuel diversity remains an important hedge against portfolio (particularly natural gas) price volatility and
a key attribute to a robust resource plan. The cost-effective acquisition of renewable energy at fixed prices improves fuel diversity and reduces portfolio (price) volatility.

Implementation of the CPP Rule by the states will likely determine what compliance flexibilities are available, whether New Mexico and Texas (“NM/TX”) will implement rate-based or mass-based programs, whether an individual state will collaborate with other states in multi-state plans, and how much of the CO₂ reduction burden each state will assign one utility versus other utilities. Given the current information regarding the CPP Rule and the resultant target emission levels by state, compliance in Texas (791 lbs/MWh target) will be more difficult to achieve than in New Mexico (1,048 lbs/MWh). However, because SPS operates as an integrated and multi-state utility, Texas requirements will impact all SPS customers. At this time, SPS does not know whether NM/TX intend to assign compliance obligations only to regulated power plants, or take a portfolio approach (at the state level or through a multi-state cooperative program) that allows SPS to implement various power plant, renewable energy, EE, and other measures necessary to achieve aggregate cost reductions across a larger geographical footprint.

In summary, major unknown factors, which influence resource planning decision, include:

- What the final rule may entail, which could include different Interim and Final goals for SPS, due to both technical corrections that have been identified, and better recognition of early action that SPS is encouraging the EPA to provide.

- The form that each state plans will take in the SPS system’s two states; specifically, whether these plans will be based only on direct emission limits for affected EGUs, in effect assigning the full compliance obligation to the owner/operators of these EGUs, or if they will adopt what the EPA has termed a state-driven or utility-driven portfolio approach, both of which would assign a portion of the compliance obligation to affected entities other than EGU owner/operators.
• Whether the states will prepare state-only compliance plans or collaborate with any other states within or outside the SPS system.

• Whether the states will implement rate-based plans, planning and measuring compliance against the lbs CO₂/MWh goals in the final rule, or instead exercise its option to convert these goals to mass budgets (total tons of CO₂ per year).

• How much of the emission reduction obligation the states must achieve will be assigned to SPS and how much to other utilities in the state.

All of these “known/unknowns” play a significant role in SPS generation plans, particularly in subsequent Integrated Resource Plans.

*Implications of GHG Regulations for Resource Planning*

At this time, great uncertainty remains about the final form of the three proposed EPA rules (for new, modified/reconstructed, and existing sources) described above, including implementation, which could be delayed as the proposed rules are challenged. The new and modified/reconstructed source rules are expected to have less overall impact on SPS’s plans, as discussed earlier.

However, the existing source rule, and the states’ implementation plans, will have significant impacts on SPS’s system. As a result of the significant uncertainty, SPS has not modeled the proposed and modified GHG regulations in its 2015 IRP. Given the uncertainties, SPS cannot model the proposed and modified rules, but SPS has continued the practice of modeling carbon proxy pricing to simulate a carbon-regulated future (discussed later). However, unless the final rules are dramatically different from the proposed rules, SPS can expect pressure to continue its downward carbon trajectory, while at the same time facing challenges for operating its fossil resources, to overall affordability, and for maintenance of fuel diversity. Accordingly, SPS’s 2015 IRP is premised on the existing uncertainty and a key driver of SPS’s preferred resource plan. In particular, SPS’s preferred plan is guided by the following factors:
• *There is no single answer.* SPS must rely on a diverse portfolio of resources to bridge the gap to a clean energy future. Integrated transmission planning will be a critical component of this strategy because it can link utility customers to distant renewable energy resources. New gas supply infrastructure will also be key, to the extent CPP Rule compliance is achieved through increased utilization of existing and construction of new gas plants.

• *Flexibility is key.* As energy generation, transmission, distribution, and storage technologies evolve, SPS must have the flexibility to adjust its strategies. Further investment in research, development, and deployment will be needed to meet the challenges of the new energy landscape. Fundamental changes in the utility regulatory structure may also take place.

B. Particulate Matter, Oxides of Nitrogen, and Sulfur Dioxide Emissions

Particulate matter (“PM”), including “coarse” PM under 10 micrometers in diameter (PM$_{10}$) and “fine” PM under 2.5 micrometers (PM$_{2.5}$), nitrogen dioxide (“NO$_2$”) and sulfur dioxide (“SO$_2$”) are three of the six “criteria pollutants” regulated by the EPA under the CAA. These pollutants are regulated under three primary programs: National Ambient Air Quality Standards (“NAAQS”), CAA programs that address interstate transport of air pollution, and CAA programs that address visibility impairment in national parks and wilderness areas. Each of these is addressed in turn.

*National Ambient Air Quality Standards*

The CAA requires the EPA to set NAAQS to protect public health and the environment. NAAQS include both: (1) primary standards to protect public health, including the health of sensitive populations, such as asthmatics, children, and the elderly; and (2) secondary standards to protect public welfare, including protection against damages to animals, crops, and buildings. The EPA has established NAAQS for six criteria pollutants: PM, NO$_2$, SO$_2$, ozone, carbon monoxide, and lead. The EPA is required to review the NAAQS every five years and revise them as
appropriate to protect public health and welfare. The NAAQS program has been in place since the early 1970s.

Once the EPA adopts or revises a NAAQS, states have two years to monitor their air, analyze the data and submit to the EPA their classification of the state into Attainment Areas (areas having monitored ambient air quality concentrations below the NAAQS), Nonattainment Areas (areas having monitored ambient air quality concentrations above the NAAQS), and unclassifiable areas. The EPA reviews the state’s submittal and determines the final area designations a year later. When the EPA designates an area as Nonattainment, the state is generally given three years to develop a new State Implementation Plan (“SIP”) which identifies actions to be taken to bring the area back into Attainment. A SIP must include emission reduction requirements needed to demonstrate that air quality will attain the NAAQS in the timelines required by the CAA – usually within two to seven years after the SIP is submitted to the EPA for approval. Since the NAAQS are individually reviewed and revised for each pollutant, the descriptions below show the timelines that apply to current and upcoming NAAQS revisions by pollutant.

**Coarse Particulate Matter (PM₁₀) and Fine Particulate Matter (PM₂.₅)**

On January 15, 2013, the EPA finalized NAAQS for both PM₁₀ and PM₂.₅. The EPA lowered the primary (health-based) NAAQS for annual PM₂.₅ from 15 to 12 microgram per cubic meter ("μg/m³"), and retained the established 24-hour PM₂.₅ standard, which was set at 35 μg/m³ in 2006. The EPA also retained the existing standards for PM₁₀.¹⁴

The EPA established the following timeline for implementation of the new PM₂.₅ NAAQS in New Mexico and Texas:

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¹⁴ The EPA established the PM₂.₅ NAAQS in 1997. In 2006, the EPA lowered the daily PM₂.₅ standard from 65 μg/m³ to 35 μg/m³.
Table 3-10: Estimated PM Regulatory Timeline

<table>
<thead>
<tr>
<th>Action</th>
<th>Timeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPA finalizes revised particle NAAQS</td>
<td>January 2013</td>
</tr>
<tr>
<td>States submit designation recommendations to the EPA</td>
<td>2014</td>
</tr>
<tr>
<td>EPA designates areas as attainment, nonattainment or unclassifiable</td>
<td>2015</td>
</tr>
<tr>
<td>State Implementation Plans due to the EPA</td>
<td>2018</td>
</tr>
<tr>
<td>Attainment Date (5-10 years after nonattainment designation)</td>
<td>2020-2025</td>
</tr>
</tbody>
</table>

Current monitored air concentrations of PM$_{2.5}$ in New Mexico and Texas are below both the 24-hour and the annual primary standard. The EPA has projected that New Mexico would remain in attainment for the new annual standard for PM$_{2.5}$. In December 2013, states submitted their air quality data to the EPA and asked that all their areas be designated as in attainment of the new annual standard. In August 2014, the EPA issued its proposed designations, which did not include any nonattainment areas in the states in which SPS operates. In December 2014, the EPA finalized those designations and did not classify any areas as nonattainment in any of SPS’S two states.\textsuperscript{15} If areas were to be designated as nonattainment for PM$_{2.5}$ at some point in the future, this could require SO$_2$ and/or Nitrous Oxide (“NO$_x$”) emission reductions from SPS’s thermal generation units as these pollutants are precursors to PM$_{2.5}$.

Every five years, the EPA reviews the scientific data on health effects and decides whether any revision to the PM NAAQS is needed. It is not known what adjustments to the PM NAAQS, if any, the EPA may make after its next review cycle, which will occur in the 2018-19 timeframe. If the NAAQS were to be made more stringent, the states would conduct a SIP planning process to assess New Mexico and Texas air quality, evaluate emission reduction options and impose

\textsuperscript{15} See all designated nonattainment areas at http://www.epa.gov/pmdesignations/2012standards/regs.htm.
appropriate emission reduction requirements on similar time intervals as shown in Table 3-10 above for the 2013 standards, but starting in 2018 with final compliance in the 2025-2030 timeframe.

**Ozone (O3)**

Ozone (also called smog) is formed from the reaction of NO$_x$ and volatile organic compounds in the presence of sunlight. Ozone levels are highest in the summer months. In 2008, the EPA finalized the current NAAQS for ozone, which is more stringent than the previous ozone NAAQS adopted in 1997. The primary NAAQS for ozone is an eight-hour standard of 75 parts per billion ("ppb"). The EPA has designated all of New Mexico as in attainment of the 2008 ozone NAAQS.

In April 2014, the U.S. District Court for the Northern District of California issued an order directing the EPA to propose a revised NAAQS for ozone by December 1, 2014, and to issue a final rule by October 1, 2015. On November 25, 2014, the EPA released its proposed Ozone NAAQS, proposing to set both the primary (public health) and secondary (public welfare) standards as 8-hour standards within a range of 65 to 70 ppb, although they are taking comments on 60 ppb as the level for the primary standard. In 2015, the EPA will finalize the revisions to the NAAQS, after which the EPA will classify areas (in 2017) and, if there are nonattainment areas, the relevant state agencies will develop a state implementation plan for 2019-20. In the state planning process, relevant state agencies would evaluate whether to require additional NOx controls at any of SPS’s plants.

SPS estimates that the regulatory process to implement a new standard will develop on the following schedule:
Table 3-11: Estimated Ozone Regulatory Timeline

<table>
<thead>
<tr>
<th>Action</th>
<th>Timeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPA proposes new ozone NAAQS</td>
<td>Late 2014</td>
</tr>
<tr>
<td>EPA finalizes new ozone NAAQS</td>
<td>October 2015</td>
</tr>
<tr>
<td>States submit designation recommendations to the EPA</td>
<td>2016</td>
</tr>
<tr>
<td>EPA designates areas as attainment, nonattainment or unclassifiable</td>
<td>2017</td>
</tr>
<tr>
<td>State Implementation Plans due to the EPA</td>
<td>2019-2020</td>
</tr>
<tr>
<td>Attainment Date (5-10 years after nonattainment designation)</td>
<td>2022-2027</td>
</tr>
</tbody>
</table>

Depending upon the level of the final standard, portions of New Mexico may not be in attainment with the standard. For example, based on current monitoring data, all of New Mexico and Texas would be expected to attain an ozone standard of 70 ppb, and if part of New Mexico or Texas is designated nonattainment for ozone, the state would be required to develop a SIP to achieve further emissions reductions of compounds that contribute to ozone formation on the approximate timeline shown above. Such a SIP would consider reductions needed and possible reductions from many different sources of ozone precursors. Thus, an ozone SIP may focus primarily on reducing NO\textsubscript{x} emissions from mobile and non-point sources, but installation of additional NO\textsubscript{x} controls at our fossil power plants might be required. It is also possible that New Mexico can avoid nonattainment for ozone, resulting in no requirement for additional controls. A 60 ppb standard would put some areas of the SPS system in nonattainment.

**Nitrogen Dioxide**

In 2010, the EPA finalized a revised primary NO\textsubscript{2} NAAQS. The EPA retained the existing annual average of 53 ppb and set a new one-hour standard of 100 ppb. Currently, all New Mexico sites meet the annual and one-hour NO\textsubscript{2} NAAQS. The EPA completed area designations in early 2012, finding no area in the country to be in Nonattainment. The state reported that in 2011,
monitors showed concentrations in New Mexico at levels less than half of the levels allowed by the NO₂ NAAQS.

NO₂ concentrations near roads are usually higher than at other locations due to mobile sources. To take this into account, the new NO₂ NAAQS changed the requirements for state ambient air monitoring networks. The EPA recently established a phased schedule for states to amend their monitoring network plans to include near-road monitors, requiring them to be operational starting in the years between 2014 and 2017. The regulatory process to address nonattainment, if any, would develop on approximately the following schedule:

**Table 3-12: Estimated NO₂ Regulatory Timeline**

<table>
<thead>
<tr>
<th>Action</th>
<th>Timeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>New NO₂ roadway monitoring begins</td>
<td>2014-2017</td>
</tr>
<tr>
<td>EPA issues nonattainment redesignations</td>
<td>2017-2018</td>
</tr>
<tr>
<td>State Implementation Plans due to the EPA</td>
<td>2020</td>
</tr>
<tr>
<td>Attainment Date (5-10 years after date of Nonattainment)</td>
<td>2022-2027</td>
</tr>
</tbody>
</table>

If New Mexico cannot attain the NO₂ standard, the state would need to develop a SIP to address the nonattainment. It is unclear what strategy the state would take in this situation, since roadway monitors would record emissions mostly from mobile sources. SPS believes that the state would be more likely to target mobile sources for reductions if nonattainment is based on results from a near-road monitor.

**Sulfur Dioxide (SO₂)**

The EPA last revised the primary SO₂ NAAQS in 2010, setting a one-hour standard of 75 ppb and a three-hour standard of 0.5 ppm. The EPA made its final designations for areas not attaining the SO₂ NAAQS in 2013 and did not include any areas in New Mexico.
There exists the potential for a requirement of additional controls at the SPS coal-fired power plants to control SO₂ emissions. SPS system coal plants do not have scrubbers, dry sorbent injection ("DSI"), or any other SO₂ control system installed. In the event that various nonattainment areas in the SPS region are designated by EPA, SPS would then be potentially required to install SO₂ controls to meet compliance requirements with a SIP to meet the goals of the nonattainment area. This could include scrubbers, DSI, or a host of other combinations of control technologies to meet the SIP. This will be unknown until the designations are made and the states develop SIPS for compliance. Furthermore, the current proposed Regional Haze Federal Implementation Plan ("FIP") (discussed later) requires the installation of dry scrubbers on the Tolk Station units. There is also the possibility of the DSI installation in lieu of scrubbers.

**Table 3-13: Estimated SO₂ Regulatory Timeline**

<table>
<thead>
<tr>
<th>Action</th>
<th>Timeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPA issues Nonattainment Redesignations</td>
<td>2016</td>
</tr>
<tr>
<td>State Implementation Plans due to the EPA</td>
<td>2019</td>
</tr>
<tr>
<td>Attainment Date (5 years after date of Nonattainment)</td>
<td>2021</td>
</tr>
</tbody>
</table>

**Carbon Monoxide**

The EPA completed its review of the primary CO NAAQS and in 2011 published its final determination to maintain the existing eight-hour standard at 9 ppm and the one-hour standard at 35 ppm. New Mexico is currently in Attainment with the carbon monoxide NAAQS. SPS does not foresee that status changing in the near future.

**Lead**

In 2008, the EPA finalized a new NAAQS for lead that made the standard substantially more stringent at 0.15 μg/m³ (rolling three-month average). With the exception of a monitoring site located near Gopher Resource Corporation’s lead recycling facility in Eagan, existing lead
monitoring sites within New Mexico meet the lead NAAQS. SPS does not foresee any further areas of Nonattainment in New Mexico in the near future.

**Implications of NAAQS Regulatory Developments**

The revisions to all six NAAQS were finalized between 2008 and 2012 to reflect the latest scientific information about the health effects of these air pollutants. Despite several NAAQS being significantly tightened, at present, there are no Nonattainment areas in New Mexico that might result in SIP emission reduction requirements being imposed. However, SO\textsubscript{2} or NO\textsubscript{x} emission reductions might be required if New Mexico or Texas have areas that do not meet the proposed new (lower) ozone NAAQS, or if in the future areas become Nonattainment for PM\textsubscript{2.5}. According to the NAAQS implementation schedules shown above, further reductions might be required to be achieved in the early to mid-2020s, but only if counties in SPS’s territory enter Nonattainment for SO\textsubscript{2}, ozone, or particulate matter.

If areas of the state are classified Nonattainment with any of the NAAQS, this would tend to affect state planning more than utility resource planning. When developing the SIP to address Nonattainment, the state would need to address point source emissions inside of the Nonattainment area, mobile source emissions inside of the Nonattainment area, area and residential source emissions inside of the Nonattainment area, and transport of air pollution across state boundaries.

The only additional control equipment that could be required would be SCR technology to further reduce NO\textsubscript{x} emissions from one or more of the Texas units. Given the NAAQS timetables shown in the tables above, SCR installation could be required, if at all, at the earliest in the early to mid-2020s. Depending on where the ozone NAAQS standard is set, it is also possible that New Mexico could remain in Attainment for ozone (requiring no additional NO\textsubscript{x} controls), or that New Mexico
Mexico could be in Nonattainment but emission reductions would be required from other sectors. Furthermore, if the EPA designated SO$_2$ Nonattainment areas in SPS territories, there is the potential for installation of SO$_2$ controls at some facilities to meet the SIP to comply with the nonattainment designation. This could include scrubbers, DSI, fuel conversions or a host of combinations of control technologies. These would be undetermined until a SIP was in place.

**Interstate Transport of Air Pollution**

The CAA also requires that NAAQS SIPs include provisions that prevent sources within a state “from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any” NAAQS. The EPA has developed programs for the Eastern U.S. that would reduce interstate transport of pollutants that are precursors to ozone and fine particles. Oxides of nitrogen are a precursor to ozone and fine particle formation, while SO$_2$ is a precursor to fine particle formation. For the utility industry, the current program is the Cross-State Air Pollution Rule (“CSAPR”), which went into effect January 1, 2015.

CSAPR was designed as a “cap-and-trade” program that reduces overall emissions from EGUs. This means that total emissions from EGUs in a state or region are limited (the cap), and each ton of emissions allowed is represented by an emission allowance that can be transferred among EGUs (the trade). A cap-and-trade program thus reduces total emissions to the capped amount, but provides flexibility for EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both. Depending on the EPA’s analysis of an upwind state’s contribution to

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Nonattainment in downwind states, CSAPR imposes one or both of the following emission limitations: (1) summer season NO\textsubscript{x} emissions (to address ozone), and/or (2) annual NO\textsubscript{x} and SO\textsubscript{2} emissions (to address fine particles).

There has been significant litigation related to CSAPR. In December 2011, the D.C. Circuit stayed the effectiveness of CSAPR and instructed the EPA to continue administering a predecessor rule (the Clean Air Interstate Rule (“CAIR”)) pending the Court’s resolution of the appeals filed against the CSAPR. In August 2012, the U.S. Circuit Court of Appeals for the D.C. Circuit issued an opinion finding the CSAPR to contradict the CAA, vacated it, and instructed the EPA to continue administering the CAIR pending adoption of a valid replacement.

In April 2014, the U.S. Supreme Court reversed and remanded the case to the D.C. Circuit. The Supreme Court held that the EPA’s design of CSAPR did not violate the CAA, and that states had received adequate opportunity to develop their own plans. Because the D.C. Circuit overturned the CSAPR on two over-arching issues, there are many other issues the D.C. Circuit did not rule on that will now need to be considered on remand.

SPS currently forecasts compliance with the current CSAPR emission limits, without installation of additional controls, through the purchase of SO\textsubscript{2} and NO\textsubscript{x} allowances. In the future, EPA may reduce the SO\textsubscript{2} and NO\textsubscript{x} emission allowance levels if the ozone or particle NAAQS are made more stringent and if further reductions are needed to assist nonattainment areas in downwind states. Depending on the level of reductions needed, SPS might be required to install additional controls for NO\textsubscript{x}, but SPS does not project further SO\textsubscript{2} controls due to CSAPR.
Visibility Impairment in National Parks and Wilderness Areas (Regional Haze)

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees. In 1977, the CAA established a national goal of remediating existing and preventing future visibility impairment from man-made air pollution in specified “Class I” areas – national parks and wilderness areas throughout the United States, including New Mexico and Texas.

The EPA has taken a two-phased approach to implement this program. The first phase, reasonably attributable visibility impairment (“RAVI”), was implemented in the 1980s to address visibility impairment reasonably attributable to a specific source. The EPA adopted regulations for this program designed to address plume blight, defined as “smoke, dust, colored gas plumes, or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or a small group of sources.”

The second phase was designed to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. In 1999, the EPA adopted its Regional Haze Rule (“RHR”) to address this type of visibility impairment. State environmental agencies are required to submit SIPs that develop and implement their strategy to reduce emissions that may contribute to regional haze. RHR SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no man-made visibility impairment in Class I areas by 2064. These SIPs focus on emissions of SO₂, NOₓ, and particulate matter, and must be revised approximately every ten years to continue reasonable progress toward reaching the 2064 national goal. The New Mexico Regional Haze SIP
does not affect any SPS New Mexico facilities. However, the Tolk Station facility in Texas is subject to the EPA’s FIP for Region Haze (TX166.001).

The EPA rejected portions of the state of Texas plan to address haze in national parks or wilderness areas and has instead proposed a federal plan for Texas. The EPA’s plan requires additional and more costly emission controls (scrubbers), specifically on SPS’s Tolk Station plant near Muleshoe, Texas. SPS believes these additional controls are unjustified with insignificant actual benefits, requiring SPS’s customers to expend hundreds of millions of dollars to improve visibility in a federal wildlife refuge in western Oklahoma and the Guadalupe Mountain National Park of west Texas. SPS, through its parent company Xcel Energy, has submitted comments challenging this proposal to the EPA. A final rule and FIP is scheduled to be published by EPA in December of 2015.

Regulation of Coal Combustion Residuals (Ash)

Coal Combustion Residuals (“CCRs”), often referred to as coal ash, are currently considered exempt wastes under the federal Resource Conservation and Recovery Act (“RCRA”) and are regulated under state solid waste programs. Coal ash is residue from the combustion of coal in power plants. Generally, CCRs are captured by pollution control equipment and either recycled for beneficial reuse or disposed of appropriately as non-hazardous industrial waste. Environmental issues involving coal ash derive from concerns regarding structural failure of large surface impoundments (e.g., the 2008 Tennessee Valley Authority Kingston ash pond failure, and more recent incidents at Duke Energy power plants in the Southeast U.S.), allegations of inconsistent

oversight by the states, and the potential for releases from unlined ash impoundments and landfills to impact drinking water sources.

Currently the CCRs that result from the combustion of coal at SPS units are 100 percent beneficially used in dry form and marketed by an onsite marketing facility for use. There are no wet operations for ash management in SPS.

SPS’s operations are subject to federal and state laws that impose requirements for handling, storage, treatment, and disposal of wastes. On December 19, 2014, the EPA signed a final rule establishing national standards for the management and disposal of CCRs. The rule regulates this material as a non-hazardous waste under Subtitle D of the RCRA. The rule establishes minimum design and operating requirements for CCR landfills and surface impoundments that are comparable to SPS’s current requirements under State enforceable, site-specific permits, and operating plans. SPS has evaluated the rule and determined the rule will have minimal direct impact on SPS’s operations or costs. As long as ash remains viable to the industry and current control technologies that may be required under other air regulations do not chemically or physically change the ash, 100 percent beneficial use of ash will be maintained. In the event the installation of controls through other regulations renders the ash unusable for market purposes, SPS will be required to follow this rule for disposal potentially requiring the installation and maintenance of ash landfills and monitoring.

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C. Water Quality Regulation

Cooling Water Intake Structures

Section 316(b) of the federal Clean Water Act (“CWA”) requires the EPA to develop regulations governing the design, maintenance, and operation of cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse impacts to aquatic species. The regulations must address both impingement (the trapping of aquatic biota against plant intake screens) and entrainment (the protection of small aquatic organisms that pass through the intake screens into the plant cooling systems).

SPS’s Texas and New Mexico facilities are not affected by this rule because no SPS facilities withdraw surface water for cooling purposes. In addition, SPS does not operate any cooling ponds.

Thermal Discharge

The EPA regulates the impacts of heated cooling water discharge from power plants under CWA Section 316(a). States with authority to implement and enforce CWA programs have state-specific water quality criteria including thermal discharge temperature parameters to protect aquatic biota. Plants must operate in compliance with the thermal discharge temperature parameters. SPS facilities are not subject rule because they do not discharge any heated cooling water from power plants to surface waters.

Effluent Limitation Guidelines

As part of the National Pollutant Discharge Elimination System (“NPDES”) process, the EPA identifies technology-based contaminant reduction requirements called Effluent Limitation Guidelines (“ELGs”). The ELGs are used by permit writers as the maximum amount of a pollutant
that may be discharged to a water body and apply to power plants that use coal, natural gas, oil, or nuclear materials as fuel and discharge treated effluent to surface waters, as well as to utility-owned landfills that receive CCRs. ELGs are periodically updated to reflect improvements in pollution control and reduction technologies.

The EPA published a proposed ELG rule in June 2013. EPA is currently reviewing public comments and anticipates issuing a final rule in September 2015. The revised ELGs would be implemented as required as each facility’s NPDES permit is renewed between 2015 and 2020, with final facility compliance following five years after permit issuance and acceptance.

The EPA will continue to regulate contaminants in the effluent discharged from power plants to surface waters. It is expected that some of the existing ELGs will be made more restrictive, but the extent of the reductions and the impacts to power plant operations is not estimable at this time. States that implement the federal NPDES have the authority to implement more restrictive requirements than are currently in place and it is possible that states will utilize the extensive docket of information published in the EPA proposal to justify more stringent discharge limits.

*Waters of the United States*

In April 2014, the EPA and the U.S. Army Corps of Engineers (“USACE”) issued a proposed rule to revise the regulatory definition of “waters of the United States” (“WOTUS”). The proposal would significantly expand the universe of land features and water bodies that are subject to CWA jurisdiction. Under the CWA, federal permitting and oversight are required for any activity having the potential to impact WOTUS. Although the plain language of the CWA limits federal jurisdiction to “navigable” waters, federal agencies have broadly interpreted that to include
adjacent waters, wetlands, man-made ditches, and ephemeral streams. A final rule was published in the Federal Register on June 29, 2015.

SPS’s review of the EPA’s proposal indicates that the new definition would impact SPS in a number of ways by adding complexity, cost, and delay to project permitting. Current operations would also be impacted by the imposition of new regulatory requirements to previously exempt onsite or adjacent water bodies or ditches. The proposed changes would:

- Increase the difficulty of siting gas pipeline and transmission line projects, since many more areas will need to be avoided or else be subject to extensive and time-consuming CWA permitting;
- Complicate certain distribution line routing/re-routing work by triggering a lengthy permitting process before work can be conducted in or near WOTUS, for example, when SPS is required to reroute its lines due to state and local highway projects;
- Complicate the process to site, permit, and construct power plants, wind and solar facilities, or other construction areas, particularly in areas that have isolated water features. Additional time and cost will be incurred to either obtain the permits or to avoid areas that would trigger the need for federal permitting; and
- Increase cost and potential reliability issues as existing facilities, especially substations, must be retrofitted with additional oil-spill prevention and containment features to prevent an oil release from reaching WOTUS.

3.09 - Impacts Due to an Aging SPS Generation Fleet

Aging fossil fuel generating units is becoming a critical issue facing SPS, as replacement of existing generation generally places upward pressure on rates when incremental costs are higher than average (embedded) costs. Average generation age of the SPS fleet is approximately 42 years old. Some generation facilities are 60 to 70 years old. Several of SPS-owned generation units are at the end of their useful life and either must be retired or totally refurbished/rebuilt. Retirement of certain generation could create transmission reliability problems, depending on the location,
resulting in increased transmission expenditures. The cost and operational advantage of new technology could outweigh the benefits and cost of maintaining existing or rebuilt generation. SPS must weigh the costs and benefits of acquiring new capacity either through self-build or purchased power compared to the cost of maintaining an aging generation fleet.

3.10 - Impacts Due to High Variability in SPS Forecasted Loads

Over the last several years, SPS has experienced an increased variability in system load growth. Much of the variability in load growth is being driven by the volatility in oil and natural gas prices. Increased variability in loads creates additional risk that does not exist in a system that is characterized by stable growth in system loads. Providing reliable service for a system containing significant load variability will cost more than a system without such load variability.

Consider that prior to 2007, SPS had approximately 300 MW of demand response load (i.e., 300 MW of customer load which could be interrupted as system conditions necessitated). This relationship benefited both the interruptible customer, in the form of a reduced rate, and the remaining customers, because rates paid to the interruptible customer were less than system avoided cost. However, as oil prices began to increase, many of these customers found it no longer beneficial to remain on the interruptible rate schedules. At the same time, the economics of higher oil prices caused many oil-related customers to initiate a very aggressive capital expansion plan, resulting in an increase in forecasted obligation load. However, as oil prices decrease, oil-related capital expansions also decrease, ultimately impacting SPS in terms of reductions to the forecasted obligation load.

These “on-again off-again” plans for capital expansion in the oil sector directly impacts SPS’s resource planning. A conservative approach (to generation resource planning) is to design a
system capable of serving the expected oil-related load growth, but no more than the expected load growth, which could result in SPS’s inability to provide service to some new loads (including non-oil loads). Another approach is to design a generation resource plan capable of covering the expected load growth plus some level of load growth uncertainty.

The choice between a conservative and flexible approach to generation resource planning depends upon many competing factors including the risks created due to the size of the potential variability in new load growth, the rate and timing of this new load growth, and the cost of the ability to reliability serve this additional new load growth variability.

3.11 - Identification of Critical Facilities Susceptible to Supply-Source or Other Failures and Summary of Back-up Fuel Capabilities and Options

SPS takes system reliability very seriously and devotes significant resources to protecting the system from multiple types of risks. The SPS transmission system is designed to single contingency or N-1 standards and therefore has the ability to sustain service in the face of various types of generator and transmission contingencies. In addition, SPS is compliant with the NERC reliability standards which require that assets critical to operation of the bulk electric system be identified and special protections for those facilities implemented. For safety and reliability, any lists or descriptions of these critical assets are considered highly confidential and not available to the public domain. Further, all of SPS’s owned generation units have redundant fuel supplies, mitigating the risk of supply-source failures. With the recent move from SPS as the Balancing Authority to SPP as the Balancing Authority, the entire generation market is operated differently. Other SPP market generation would address any deficiencies in SPS resources.
Section 4. CURRENT LOAD FORECAST

4.01 - Forecast Overview

Projections of future energy sales and coincident peak demand are fundamental inputs into SPS’s resource need assessment. As required by the IRP Rule, SPS has prepared base, high, and low case scenario forecasts (17.7.3.9(D)(2) NMAC).

SPS projects its base or median electric firm obligation load (firm retail and firm wholesale requirements customers) to increase at a compounded annual growth rate of 1.3 percent or an average of 70 MW per year through the Planning Period. SPS’s base or median energy sales are forecasted to increase at a compounded annual growth rate of 1.7 percent or an average of 526 GWh during the same period. The load increase over the Planning Period contrasts to the historical annual average load growth of 1.1 percent over the last 10 years (ending 2014). The historical annual average energy growth over the ten years ending 2014 is 0.3 percent. Driving load and energy increases is the oil and gas expansion in Southeastern New Mexico and potash mining expansions. The decline of wholesale load, due to expiration of the Eastside Cooperatives wholesale contracts and contractual changes within existing wholesale contracts, offsets some of the historic, as well as future, growth.

SPS’s low forecast scenario of coincident peak demand increases at a compounded growth rate of 0.6 percent through the Planning Period, and the high forecast scenario of coincident peak demand grows at a compounded rate of 1.8 percent per year. Figure 4F.1 below contains a graphical representation of the low and high forecast scenarios of coincident peak demand.
SPS’s low annual energy sales forecast scenario increases at a compounded annual growth rate of 0.9 percent through 2035, and the high annual energy sales forecast scenario increases at a compounded rate of 2.4 percent per year. Figure 4F.2 below contains a graphical representation of the low and high scenario forecasts of annual energy sales.

**Figure 4F.1: Coincident Peak Demand Forecasts**

**Figure 4F.2: Energy Sales Forecasts**
Figures 4F.1 and 4F.2 (above) show the base, high, and low forecasts for firm coincident peak demand and annual energy sales graphically. Appendix D (Tables D-10 and D-11) provides the data supporting the charts. Appendix D (Table D -11) also shows the SPS forecast for its total annual energy sales with fifteen years of history starting in 2000, and it shows annual growth and compounded growth to/from 2014. The bold line across the table delineates historical from projected information.

The base peak demand forecast assumes economic growth based on projections from IHS Global Insight, Inc. (“Global Insight”) and normal summer peak weather conditions. SPS estimates a 70 percent probability that the actual peak demands and energy sales will fall between the high and the low forecast scenarios.

4.02 - Peak Demand Discussion

Firm peak demand in the SPS service territory has grown moderately over the last 10 years (through 2014). SPS’s firm peak demand increased by 520 MW, or 12.0 percent, from 2005 to 2014. Load growth was dampened as a result of decreased demand from wholesale customers due to changes in contracted load and the settlement agreement with the New Mexico Co-ops. In the 10-year period ending 2014, the population in the SPS service territory grew by an annual average rate of 0.7 percent per year. Combined New Mexico and Texas Gross State Product (“GSP”) averaged annual gains of 3.2 percent from 2005 through 2014. During this same period, SPS lost 2.1 percent of its residential customers due to the loss of approximately 18,000 residential customers when the City of Lubbock assets were sold to Lubbock Power & Light. When the loss of residential customers from the Lubbock sale was netted out, SPS’s residential customer base increased by approximately 17,800 customers (or 6.2 percent) from 2005.
The peak demand forecast compounded annual growth rate for the planning period through 2035 is 1.3 percent. This is slightly higher than the ten-year period ending in 2014 with a compounded annual growth rate of 1.1 percent. Retail peak demand for the planning period increases at a compounded annual average growth rate of 2.8 percent, compared to the ten-year period ending 2014 compounded annual average growth rate of 1.8 percent. Since 2004, the historical growth in SPS’s retail sector has been fueled by oil drilling and gas extraction in Southeastern New Mexico. SPS expects strong growth in the retail sector due to additional increases in oil and gas load coming on to the system during the resource planning period.

Wholesale peak demand for the planning period decreases at a compounded annual growth rate of 9.1 percent, compared to the ten-year period ending 2014 compounded annual average growth rate of 0.3 percent. The decline of wholesale load is due to the settlement agreement with the Co-ops, wholesale contracts ending, and contractual changes within existing wholesale load offset growth. SPS assumes that these wholesale contracts will not be renewed after their known expiration dates.

Combined growth in Texas and New Mexico GSP is calculated at 3.2 percent in 2014, followed by an average growth rate of 4.4 percent during the planning period. Population growth will mimic the recent past, with annual gains averaging 0.7 percent through the planning period. SPS projects residential customer growth will average annual increases of 0.5 percent per year through 2035.

Table D-4 in Appendix D (Electric Energy and Demand Forecast) shows the SPS coincident peak demand by retail and wholesale customer categories. Figure 4F.3 (below) shows the SPS coincident peak demand by retail and wholesale customers graphically.
4.03 - Annual Energy Discussion

SPS is calling for energy sales in the base case forecast to experience strong growth over the planning period. The expected declines in wholesale energy sales corresponding to the termination or reduction of sales to specific wholesale customers will be offset by growth in the retail sector.

During the past ten years SPS has experienced moderate growth in energy sales. Energy sales increased by 344 GWh, or 1.3 percent, from 2005 to 2014. From 2016 to 2035 SPS estimates its annual energy sales will increase by 9,328 GWh or 33.8 percent. The energy sales forecast’s compounded annual growth rate for the planning period through 2035 is 1.7 percent. This is significantly higher than the compounded annual growth rate of 0.3 percent for the 10-year period ending 2014. Retail energy sales for the planning period increase at a compounded annual average growth rate of 2.9 percent, compared to the 10-year period ending 2014 compounded annual average growth rate of 1.6 percent. Retail energy sales will benefit from stable growth in the residential sector and strong growth in the commercial and industrial sector, which is heavily
dependent on the oil and natural gas industries. Base case wholesale energy sales are forecasted to decrease at a compounded annual average growth rate of 6.3 percent for the planning period. This pace is a stronger decrease than the historical annual rate of 2.4 percent loss from 2005 to 2014. Again, the decline of wholesale load is due to the settlement agreement with the Eastside Cooperatives, wholesale contracts ending, and contractual changes within existing wholesale load. Figure 4F.4 shows SPS’s energy sales by retail and wholesale customer class graphically.

Figure 4F.4: Retail and Wholesale Energy Sales Forecasts

4.04 - High and Low Case Forecasts

Development and use of different energy sales and demand forecasts for planning future resources is an important aspect of the planning process. Alternative high and low forecast scenarios to the base case were developed for the 2015 Integrated Resource Plan. The high and low forecast scenarios are based on a Monte Carlo simulation for energy sales and peak demand forecasts with probabilistic inputs for the economic, energy, and weather drivers of the forecast models and for model error. The high forecast scenario is the forecast level from the Monte Carlo
simulation that represents a plus one standard deviation confidence band from the base case forecast. The low forecast scenario is the forecast level from the Monte Carlo simulation that represents a minus one standard deviation confidence band from the base case forecast. There is a 70 percent probability that actual energy sales and coincident peak demand will fall within the high and low forecast scenarios.

Appendix D (Table D-10 and Table D-11) provides a summarization of the base, high, and low energy sales and peak demand forecasts.

**Typical Historic Day Load Patterns**

Please refer to Appendix E for the typical day load patterns on a system-wide basis for each customer class provided for: peak day, average day, and representative off-peak days for each calendar month.

**4.05 - Forecasting Methodologies**

The following discussion describes the methods used to forecast energy sales and coincident peak demand for each of its various customer classes in SPS.

SPS forecasts retail energy sales and customers by rate class for each jurisdiction. Retail coincident peak demand is forecasted in aggregate at the total SPS level. The wholesale energy sales and coincident peak demand forecasts are developed at the individual customer level of detail. SPS models its forecasts at a monthly frequency and uses monthly historical data to develop the customers, energy sales, and coincident peak demand forecasts. Annual energy sales are an aggregation of the monthly energy sales estimates. Energy sales are forecasted at the delivery point and peak demand is forecasted at the generating source. The annual coincident peak demand occurs in July throughout the planning period 2016-2035.
Global Insight, a trusted data source for forecasting professionals, provides economic and demographic data and forecasts. SPS assumes normal weather for the forecast period. Normal weather is based on a 30-year rolling average of historical weather data for the energy sales forecasts. The retail coincident peak forecast uses a 28-year based rolling average for normal weather, because of data limitations.

4.06 - Energy Sales Forecasts

SPS’s retail customer counts, retail energy sales and full requirement wholesale energy sales forecasts are developed using econometric models and trend models. An econometric model is a widely accepted modeling approach involving linear regression analysis. Linear regression analysis is a statistical technique that attempts to understand the movement of the dependent variable, for example, energy sales, as a function of movements in a set of independent variables, such as: economic and demographic concepts, customers, price, trend, and weather through the quantification of a single equation. Other variables used in the econometric models may include autoregressive correction terms and binary variables. Binary variables are used in models to account for non-weather-related seasonal factors and unusual billing activity. The autoregressive correction term is used to aide in eliminating bias found in time-series models. After developing and testing the econometric models to identify the relationship between the dependent and independent variables, forecasts of the independent variables are used to predict future energy sales and customer counts.

SPS’s econometric models are evaluated through examining the model statistics output and tests results. Each variable coefficient in the models is checked for the correct theoretical signs and statistical significance. The coefficient of determination ("R-squared") test statistic is a measure to
verify the quality of the model’s fit to the historical data. The models are also tested for correlation of errors from one period to the next. The absence of correlation between the residual errors is an important indicator that the model is performing adequately. Graphical inspection of a model’s error term helps identify if a model suffers from auto-correlation (i.e., error terms are not random and are correlated between periods) or heteroscedasticity (i.e., inconstant variance of errors over the sample period). A model with auto-correlation may indicate model misspecification.

The output from the econometric models for the retail energy sales is adjusted to reflect the expected incremental impact of DSM programs. The model output may also be adjusted with information from SPS’s Managed Account Sales group regarding SPS’s largest commercial and industrial customers. The Managed Account Sales group provides information about known events that can impact energy sales that would not be captured in the historical data. Such events might include a scheduled increase or decrease in load for a specific customer due to a plant expansion, or a reduction in load stemming from a plant shutdown. The final adjusted output from the econometric models becomes part of the base case energy sales forecast.

Energy sales for SPS’s partial requirement wholesale customers are developed based on historical consumption patterns or econometric models as described above, subject to contractual agreement.

**4.07 - Peak Demand Forecasts**

SPS develops an econometric model, as described above, to forecast the monthly retail coincident peak demand. Total retail coincident peak demand is forecasted in aggregate at the source for the total SPS company level. The exogenous variables in the retail coincident peak demand model include weather, binary and trend variables, and retail energy sales. Retail energy
sales are not adjusted for demand-side management savings or load increases or decreases as
identified by the Managed Account Sales group prior to being used in the model. Instead, these
adjustments are made to the output from the retail peak demand model

The full requirements wholesale coincident peak demand is developed on an individual
customer basis. SPS uses a load factor methodology to calculate the coincident peak demand
associated with the energy sales for each full requirement wholesale customer. For each customer,
SPS calculates a monthly load factor based on historical energy sales and coincident peak demand
data as recorded at the delivery point. Monthly load factors are calculated as:

\[
\text{Load Factor} = \frac{\text{Energy Sales}}{(\text{Peak Demand} \times \text{Hours Per Month})}
\]

The monthly load factors are then applied to each full requirement wholesale customer’s
respective energy sales forecast to derive the monthly peak demand forecasts.

\[
\text{Peak Demand} = \frac{\text{Energy Sales}}{(\text{Load Factor} \times \text{Hours Per Month})}
\]

The peak demand forecasts are then adjusted for line losses to derive the peak demand
forecast at the source.

The partial requirement wholesale customer coincident peak demand forecasts are
determined by individual customer contractual agreement.

**4.08 - Modeling for Uncertainty**

SPS has developed high and low forecast scenarios to the base case forecast. These
alternative forecasts are derived from Monte Carlo simulations of energy sales and coincident peak
demand.

Monte Carlo simulation is a modeling technique that ascribes probabilistic characteristics to
selected inputs and the output of a model. The Monte Carlo simulations are based on econometric
models used to forecast energy sales and coincident peak demand. In particular, energy sales and coincident peak demand are modeled at the combined retail and full requirement wholesale sales level of aggregation, excluding the wholesale customer WTMPA. WTMPA is modeled separately because of how that load is handled in the generation modeling process.

In these models, probability distributions are defined for exogenous variables with inherent uncertainty associated with their forecast values. Probability distributions are a realistic way of describing uncertainty in variables. An example of a variable with inherent uncertainty is the maximum peak day temperature in the coincident peak demand model. While SPS assumes the value will be 100.5 degrees Fahrenheit for each July during the forecast period, it is unlikely that each year the actual peak day maximum temperature will be 100.5 Fahrenheit degrees. The probability distributions contain the possible values for variables with inherent uncertainty over the forecast period, based on characteristics of the data set for each variable. The weather, economic and energy variables, and the model error are assumed to have inherent uncertainty in the models used to develop the high and low energy sales and coincident peak demand forecast scenarios.

For each simulation run of these forecasting models, the values for the exogenous variables with inherent uncertainty are randomly selected from respective probability distribution. By using probability distributions, variables can have different probabilities of different outcomes occurring. Monte Carlo simulation calculates the model results over and over, each time using a different set of random values from the probability functions. The output from the Monte Carlo simulation models is then calibrated so that the 50 percent probability forecast is equal to the respective energy sales and coincident peak demand base case forecast.
4.09 - Weather Adjustments

SPS incorporates several different weather variables in its forecasting models. For the energy sales models, SPS may include monthly heating degree days, cooling degree days, and precipitation. The heating degree days and the cooling degree days are calculated on a base of 65 degrees Fahrenheit for each day and then totaled by month.

Heating Degree Days = Max (65 - Average Daily Temperature, 0)

Cooling Degree Days = Max (Average Daily Temperature - 65, 0)

The coincident peak demand models include a maximum peak day temperature variable and a rolling 1-week summation of the days prior to the monthly peak day with a maximum daily temperature of 95 degrees Fahrenheit or greater variable.

Weather during the forecast period is assumed to be normal. Normal weather is defined as a rolling 30-year average for heating degree days, cooling degree days, precipitation, and days with maximum temperature 95 degrees Fahrenheit or greater. Normal weather for the peak day maximum temperature is a 25-year average due to data limitations. The energy sales and coincident peak demand forecasts do not have any other weather normalization adjustments.

For historical periods, SPS weather normalizes historical energy sales and coincident peak demand data for variance analysis purposes. This weather normalization process involves subtracting weather-impacted energy sales or peak demand from actual sales or peak demand. Weather-impacted sales or peak demand is calculated by multiplying the forecast model weather variable coefficients by the variance of actual weather from normal weather.

Weather-Impacted Energy Sales =

Weather Coefficient * (Actual Weather-Normal Weather)
Weather Impacted Peak Demand =

Weather Coefficient * (Actual Weather-Normal Weather)

4.10 - Demand-Side Management

SPS promotes demand-side management programs that help its customers reduce energy sales and peak demand through EE and education. Xcel Energy’s DSM Regulatory Strategy and Planning group develops the projections of future and embedded DSM program savings.

SPS adjusts its retail energy sales and coincident peak demand forecasts with projected incremental DSM program savings. The incremental DSM program savings are calculated by subtracting embedded DSM savings from future DSM savings.

Incremental DSM Savings = Future DSM Savings – Embedded DSM Savings

SPS does not directly adjust its forecast models or model output for naturally occurring DSM savings that could be attributed to actions other than those of SPS. Naturally occurring DSM energy and peak demand savings are unquantifiable. However, theoretically the historical energy sales and coincident peak demand data used in SPS’s forecast modeling process does have embedded in it any naturally occurring DSM savings. Therefore, the forecast models and model output do account indirectly, through the historical data, for naturally occurring demand-side management savings. Naturally occurring DSM energy and peak demand savings do not impact SPS’s sponsored DSM resources.

4.11 - Forecast Accuracy

SPS reviews its demand and energy forecasts for accuracy annually. Overall, forecast accuracy is better in the short term than in the long term.
Appendix D (Table D-12 through Table D-17) provides a comparison the actual energy sales and firm load obligation demand forecasts to the forecasted sales and firm load obligation demands, as required by the IRP Rule. Firm load obligation equals actual load less available interruptible load. See Figures 4F.5 and 4F.6.

**Figure 4F.5: Forecast Comparison with Actual Energy Sales**

![Forecast Comparison with Actual Sales of Energy](image1)

**Figure 4F.6: Forecast Comparison with Actual Firm Load Obligation Peak**

![Forecast Comparison with Actual Firm Load Obligation Peak Demand](image2)
4.12 - Econometric Model Parameters

Please refer to Appendix F, which provides the parameters associated with SPS’s econometric forecasting models.
Section 5. L&R TABLE

The IRP Rule requires that utilities provide a L&R table of existing loads and resources at the time of its IRP filing, specifically including: (1) utility-owned generation, (2) existing and future contracted-for purchased power including QF purchases, (3) purchases through net metering programs, as appropriate, (4) demand-side resources, as appropriate, and (5) any other resources relied upon by the utility.

Resource planners use a range of approaches to help identify the amounts, timing, and types of generation resources that should be added to meet increasing customer demand for electric power. One basic and straightforward tool is the L&R table. The function of an L&R table is to provide a comparison between the amount of electric generating supply and the peak load of a system. In years when load (plus some added margin\(^{19}\)) exceeds generation supply, additional generation is needed. Table 5-1 provides a summarized L&R table for the SPS electric system.

Table 5-1: Summarized L&R Table

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<thead>
<tr>
<th></th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
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<tbody>
<tr>
<td>(a) Owned Generation Capacity (MW)</td>
<td>4529</td>
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<td>(b) Purchased Generation Capacity (MW)</td>
<td>1455</td>
<td>1492</td>
<td>1497</td>
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<td>(c) Total Generation Capacity (MW)</td>
<td>5984</td>
<td>6021</td>
<td>6026</td>
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<tr>
<td>(d) Load Requirements</td>
<td>5111</td>
<td>5116</td>
<td>5313</td>
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<td>(e) Capacity Margin (12%)</td>
<td>704</td>
<td>711</td>
<td>738</td>
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<td>(f) Total Load + Reserves (MW)</td>
<td>5815</td>
<td>5827</td>
<td>6051</td>
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<td>(g) Resource Excess / Deficiency</td>
<td>169</td>
<td>194</td>
<td>(25)</td>
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\(^{19}\) Reserve margin is additional generation capacity that can be used during any contingency including: higher than expected energy demand, unplanned generation outages, and inoperable transmission infrastructure.
The L&R table above provides a number of insights into the amounts and timing of future generation resource needs. First, note that the utility has sufficient capacity in 2016 and 2017 but beginning 2018, due to load growth of 197 MW from 2017, the utility must add an additional 25 MW in 2018 to serve load and have a requisite level of reserves to cover unexpected contingency events.

SPS’s L&R table for the Planning Period (2016-2035) based on the March 2015 forecast is provided in Tables 5.2, 5.3, and 5.4 below. The L&R tables show SPS will have sufficient capacity to meet its firm load obligations for the Action Plan period (2016-2019), with the exception of 2018 where SPS is deficient capacity of 25 MW. For a more detailed discussion of the base case loads and resources, along with the low and high load forecast sensitivities, please refer to Section 7.
## Table 5.2: Summary of SPS Base Case L&R

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<td>(21)</td>
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<td>797</td>
<td>810</td>
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<td>962</td>
<td>994</td>
<td>1027</td>
<td>1062</td>
<td>1099</td>
</tr>
</tbody>
</table>

**Note:** All values are in MW.
Another useful tool for evaluating the needs of electric systems is the load duration curve. Load duration curves provide a graphic representation of how electric supply resources would operate to serve both the demand and energy requirements of the system. A load duration curve contains the total energy requirements of the system (typically over an entire year), sorted from the highest use hours to the lowest use hours. The highest number on the left hand side of the curve represents a peak energy usage during the highest energy day. By overlaying the generation stack on top of the load duration curve, one gets a general idea of how much electric power each resource type (i.e., peaking, intermediate, baseload) would be required to produce over the year.

Figure 5F.1 illustrates a hypothetical electric system that is short of baseload resources. As a result, this system will operate some of its intermediate resources in a baseload fashion.

**Figure 5F.1: Baseload Deficient**
In contrast, Figure 5F.2 illustrates a hypothetical electric system that is long on baseload resources. This system will operate some of its baseload resources at capacity factors (represented by % of hours of year) less than 40 percent.

**Figure 5F.2: Baseload Excess**

![Diagram of Baseload Excess](image)

Figure 5F.3 (below) represents a hypothetical system that is balanced with the right quantities of generation resource types. Each resource has a specific role in meeting the overall system energy needs. Each type of resource provides the necessary levels of energy that result in the lowest system costs.
Figure 5F.3: Balanced System

Figure 5F.4 (below) represents SPS’s system for 2014. SPS’s generation and purchased power capacity are shown as an overlay relative to the load duration curve. As reflected in terms of a supply curve, resources are placed in order with must-take resources first, then lowest cost and higher cost resources thereafter. SPS’s supply curve shows wind at the bottom of the load duration curve, then coal, then CC generation, and finally peaking generation which would include CTs and gas-fired steam units.

The conclusion to be reached from this load duration curve is SPS’s system is short (or in need of additional) baseload and intermediate resources. The graph shows the average capacity factor of coal (baseload) is 90 percent or greater and CC resources (intermediate) are at approximately 78 percent, which is very high for a CC resource. Typically in a balanced system, CC resources run at a 20-40 percent capacity factor (see Figure 5F.4).
Figure 5F.4: Current Load Duration Curve

2014 SPS Load Duration Curve

- 0%  5%  10%  16%  21%  26%  31%  37%  42%  47%  52%  57%  63%  68%  73%  78%  83%  89%  94%  99%

- 1,000  2,000  3,000  4,000  5,000  6,000

Coal  CC  Peaking  SPS_2014_loads  Wind
Section 6. IDENTIFICATION OF RESOURCE OPTIONS

The basic types of resources that are available for matching electricity supply and demand are discussed below. These resources play different roles in meeting a utility’s demand and energy requirements. Supply-side resources provide generation capacity to serve load, whereas demand-side resources act to reduce the level of customer demand for electric power so fewer supply side-resources are required. Supply-side resources generally fall into two categories: traditional (or thermal) and renewable. Traditional supply-side resources are typically fossil fuel based generation resources with physical fuel supplies that can be dispatched as the demand (or need) for power changes (increases or decreases) through the day. In contrast, renewable resources are intermittent supply-side “as available” generation resources, effectively the energy produced is a function of the timing and force created by the wind blowing or the solar radiation intensity and conversion of photons of light to electrical voltage (e.g., PV). Renewable resources are typically must-take resources, which can at times create operational issues related to their integration into the electrical power grid.

Examples of Traditional Supply-Side Resources

1. **CT** – These simple cycle, natural gas fired units are available in a wide range of sizes (25 MW to 300 MW). CTs are very similar to a jet engine with an electrical generator connected to the turbine shaft. CTs are typically inexpensive to build but are relatively inefficient sources of generation. The ideal role for CTs is to be run for a few hours of the year at times of the highest electric demand.

2. **CC** – These high efficiency, natural gas fired facilities use single or multiple CTs in conjunction with a Heat Recovery Steam Generator (“HRSG”). The waste heat from a CT’s exhaust gas is used to generate steam to run a steam turbine, which in turn produces additional electric power. CC units come in a variety of sizes near 100 MW to over 700
MW depending on the specific configuration of the facility. A larger sized CC generally has a lower per MW cost as a result of economies of scale. CC units have higher build costs than CT units, but lower operating costs.

Resources are categorized by how they are used: (i) peaking, (ii) intermediate, or (iii) baseload. Different thermal generation technologies have distinctly different capital and operating cost characteristics. These characteristics dictate how various technologies are dispatched or used to serve load requirements of the system. The basic cost characteristics of thermal generation resource technologies are illustrated in the following table.

Table 6-1: Cost Structure of Thermal Resources Considered in the IRP

<table>
<thead>
<tr>
<th>Costs</th>
<th>Gas CT</th>
<th>Gas CC</th>
<th>Wind</th>
<th>Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Costs</td>
<td>Low</td>
<td>Mid</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Use</td>
<td>High</td>
<td>Mid/High</td>
<td>Must-Take</td>
<td>Must-Take</td>
</tr>
<tr>
<td>CF%</td>
<td>0-25%</td>
<td>25-80%</td>
<td>45%</td>
<td>30%</td>
</tr>
<tr>
<td>CO₂</td>
<td>Medium</td>
<td>Low</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Fuel Price Risk</td>
<td>High</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Figure 6F.1 (below) provides an illustration of how the general cost characteristics of gas CTs, gas CCs and renewable resources might compare with one another based on how they are utilized (i.e., peaking, intermediate, or baseload) on the system. The figure shows that the overall cost (i.e., “all-in” cost) of electric energy per MWh depends highly on the number of hours a unit is operated, that is, the unit’s capacity factor. The “all-in” cost curves decline as the annual fixed costs (capital and operations and maintenance costs) are distributed over more hours of operation.

As seen in Figure 6F.1 (below), a gas CT is the most cost-effective when utilized in a peaking role (less than 20 percent capacity factor in this illustration), with the gas CCs being the most cost-effective in the intermediate baseload roles.
Examples of Renewable Supply-Side Resources

1. **Biomass** – Biomass energy is derived from diverse energy sources such as wood and other organic matter, animal wastes, human refuse, and alcohol derived fuels. Landfill gas is a type of biomass generation using the methane gas produced by a solid waste landfill for combustion and power production. Biomass facilities are often base loaded energy sources with capacity factors of 80 percent or better.

2. **Geothermal** – Geothermal resources convert hot underground geothermal steam/fluids into electricity and are generally run as baseload facilities and have capacity factors in the 80-90 percent range.
3. **Hydroelectric** – Flowing water is used in hydro plants to rotate a turbine and generate electric power. Run-of-river units offer continuous energy contributions, while dammed or pumped storage units offer the ability to use the facility as a peak shaving unit thereby providing additional value to the resource. Capacity factors for hydroelectric resources vary widely dependent on river flow and size of storage.

4. **Solar** – Solar generation resources convert the sun’s energy (photons of light) into electricity (voltage). Solar generation can take several forms, such as PV, Concentrating PV, or CSP. Like the wind, solar generation is intermittent. Solar generation is only available during the daytime and its output is coincident with the time of the day (i.e., as the sun rises and falls, so does the solar generation output). Maximum solar output (without storage) occurs prior to the time when electric demand reaches its highest level. Therefore, something less than the full nameplate generating capability of solar generation is counted toward meeting electric systems peak demands. Solar generation capacity factors typically range from 20-35 percent depending upon whether the resource is PV (fixed– 20 percent, 1 axis tracking – 33%) or whether the project is CSP (with storage – 35 percent).

5. **Wind** – These are typically large, three bladed turbines mounted atop high towers over 200 feet tall. Wind farms can consist of a single turbine or multiple turbines with aggregated capacities up to hundreds of MW. Because the wind drives the turbines, the generation from a wind turbine is considered intermittent and can be difficult to predict. Consequently, the electric generation capacity that is attributed to wind turbines is less than the full design output rating. Wind generation units in New Mexico and Texas typically have an annual capacity factor in the 50 percent range.

**DSM Resources**

DSM resources act to reduce the demand for electric power and include a variety of measures such as EE, energy conservation, LM, and demand response. There are two basic types of demand side resources: peak shavers and energy savers. Peak shavers are used to reduce a customer’s demand and energy requirements during periods of high demand. Examples of peak shaver DSM options include the SPS’s Commission-approved ICO (available to the business...
segment), and Saver’s Switch (available to residential and business segment customers) programs. Energy savers are used to reduce energy over all periods of the year. An example of an energy saver would be replacement of incandescent light bulbs with more energy efficient compact fluorescent bulbs to reduce energy consumption throughout the year.

**Transmission Upgrades**

Investments in transmission can be used as substitutes for investments in new generating facilities or demand-side resources, where transmission upgrades are used to access existing (or excess generation) within other transmission constrained areas.

**6.01 - Resource Options Considered**

**DSM Resources**

Cost-effective DSM (both New Mexico and Texas) is included as an offset to the corresponding base, low and high load forecasts.

**Supply-Side Thermal Resources**

1. **Gas-fired CT** - (considered for years 2020 and beyond) - Natural gas-fired CTs are available in a range of sizes (25 MW to 300 MW). CTs typically have low capital costs, but are relatively inefficient sources of generation and thus have high operating costs ($/MWh). The typical role for CTs is to be run only at times of the highest load demand or during unanticipated outages of lower cost generators (i.e., “peaking” capacity).

2. **Gas-fired CC** - (considered for years 2022 and beyond) - Natural gas-fired CC units incorporate single or multiple CTs used in conjunction with a HRSG. The waste heat from a CT’s high temperature exhaust gas is captured and used to create steam to run a steam turbine for additional power and significantly higher efficiency (i.e., a lower heat rate) than a CT operating in simple cycle mode. CC units range in generation sizes from 100 MW to 700 MW, and have higher capital costs than CT peaking units. A CC’s ideal role is to be operated in more of an “intermediate” role, which means less often than base
load resources but more often than peaking resources. The lower heat rate of CCs results in reduced fuel burn when compared to CTs for a given amount of generation, and as a result CCs have a significantly lower emission rate of CO\(_2\) compared to CTs (approximately 35 percent lower).

6.02 - Resource Option Cost and Performance Estimates

In developing the 2015 IRP, estimates were developed for the various costs, performance, and operational characteristics for the resource options discussed above. The resource options were then used in SPS’s computer modeling to represent how these various technologies would integrate with the existing SPS electric system to serve future customer load projections. Table 6-2 contains a summary of the information used to represent the various generic generation technologies that were considered in the 2015 IRP. Detailed cost and performance information related to the generic resource types is presented at pages 5-17 of Appendix G.

Table 6-2: Generic Resource Summary Cost and Performance - 2014

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capacity MW</th>
<th>Capacity Cost $/kW</th>
<th>Fixed O&amp;M $000/yr</th>
<th>On-Going Capital $000/yr</th>
<th>VOM $/MWh</th>
<th>Dispatchable</th>
<th>Heat Rate MMBtu/MWh</th>
<th>Capacity Factor</th>
<th>CO2 Emissions Lbs/MMBTu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>100</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>36.6</td>
<td>No</td>
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<td>Solar</td>
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<td>NA</td>
<td>NA</td>
<td>40.3</td>
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<td>NA</td>
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<tr>
<td>Siemens 2X1</td>
<td>831</td>
<td>702</td>
<td>2076</td>
<td>3955</td>
<td>2.61</td>
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<td>7,322</td>
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</tr>
<tr>
<td>Siemens 5000F CT</td>
<td>217</td>
<td>491</td>
<td>224</td>
<td>1066</td>
<td>1.96</td>
<td>Yes</td>
<td>10,158</td>
<td>9%</td>
<td>118</td>
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</tbody>
</table>

6.03 - Existing Rates and Tariffs

The following New Mexico retail rates and tariffs are designed to achieve LM. A general description of each tariff is provided below.

- General Service rates
- ICO
  - Summer Only ICO
- Voluntary Load Reduction Purchase Option
  - Residential Controlled Air Conditioning Rider
  - Commercial and Industrial Controlled Air Conditioning Rider
  - Residential Controlled Air Conditioning and Water Heater Rider

**General Service Rates**

All general service rates have some form of seasonality in the kWh consumption charge or the kW demand charge. Summer rates are higher than winter (non-summer) rates, which requires the customer to pay more for electricity used in higher demand, peak periods in the summer compared to the same levels of usage in winter billing months. A higher bill can serve to discourage excessive usage in summer months, and where possible for the customer, serve as an incentive to shift usage to lower demand winter billing periods.

**ICO**

Available as an option for customers who receive electric service under SPS’s Primary General Service, Secondary General Service or Large General Service Transmission rate schedules who are willing to have their service interrupted with one hour or no notice, thereby relieving SPS of the obligation to serve those customers as circumstances warrant.

**Summer Only ICO**

Available as an interruptible service option, at the discretion of SPS, when: (1) SPS determines that it has need for additional resources; and (2) SPS is interested in receiving offers from Customers for interruptible load. Customer(s) must meet each of the following conditions: (1) Customer receives electric service under SPS’s Primary General Service, Secondary General Service or Large General Service Transmission rate schedules; (2) Customer’s Contract Interruptible Load is 300 kW or greater; (3) Customer achieved (or SPS estimates that Customer
will achieve) an Interruptible Demand of at least 300 kW during each of the most recent four summer peak season months of June, July, August, and September; and (4) Customer and SPS have executed a Summer Only ICO Agreement that specifies the Contract Firm Demand and Monthly Credit Rate as well as the Customer specify data necessary for SPS to calculate the Customer’s Monthly Credit.

**Voluntary Load Reduction Purchase Option**

Applicable to Customers with at least 500 kW of peak load during each of the four summer months, June through September, which can be made available for interruption under this tariff and is not committed for interruption under another interruptible program or tariff.

**Residential Controlled Air Conditioning and Water Heater Rider**

Voluntary program in which SPS can control customer’s air conditioners and electric water heating normally designed to achieve a 50 percent reduction in the building air conditioning requirements during a period.

**Commercial and Industrial Controlled Air Conditioning Rider**

Voluntary program in which SPS can control customer’s air conditioners normally designed to achieve a 50 percent reduction in the building air conditioning requirements during a period.

**6.04 - Rate Alternatives**

SPS’s current mix of seasonal rate design, service curtailment programs, and EE programs provide a fair balance between the interest in meeting, delaying, or avoiding the need for new capacity with the interest in cost containment and adverse rate impacts resulting from significant changes in rate structures. Changes in rate design, such as Time of Use (“TOU”) rates, might provide some level of load shifting from peak periods to off peak periods by providing a price
signal that results in higher prices during peak periods and lower prices during off-peak periods. SPS plans to file a request for limited, optional TOU rates in its next base rate case. Shifting of loads may delay the need for additional capacity by reducing the need for energy supply at peak times.
Section 7. DETERMINATION OF THE MOST COST-EFFECTIVE RESOURCE PORTFOLIO AND ALTERNATIVE PORTFOLIOS

7.01 - Resource Planning Fundamentals

In its simplest form, electric resource planning is the process of taking forecasts of customer electric demand and energy use and determining the appropriate electric generation sources that should be developed to meet those customer requirements in a cost-effective and reliable fashion. Engineering, permitting, and constructing electric generating facilities takes a significant amount of time and therefore the resource planning process must be completed with adequate lead-time to allow the actual development of new resources that are needed in order to meet customer energy requirements.

Definitions

1. **Annual Capacity Factor** is the ratio of the net energy produced by a generating facility over a year, to the amount of energy that could have been produced if the facility operated continuously at full capacity over the year.

2. **Capacity** is the instantaneous capability of an electrical system to provide electricity or energy to meet demand and is usually measured in MW.

3. **Demand or load** is the level of power consumed at an instantaneous point in time.

4. **Dispatchable Resource** is a generation resource that provides the ability to physically control the generation output of that facility. Generally, thermal or storage type of units that can be “switched” on or off when requested, to a specified output.

5. **Energy** is the rate of electrical power delivered over a quantity of time and is usually measured in MWh.

6. **Generation Resource Stack** is a representation of the supply-side Dispatchable Resources sorted by operating cost, with the lowest cost generators such as coal and nuclear being at the bottom of the stack, intermediate cost generators such as CC gas units being in the
middle of the stack, and the generators with the highest operating costs (i.e., peakers) being at the top of the stack.

7. **Heat Rate** defines the efficiency of the generation unit. Generally, heat rate is measured by units of fuel burned to create one MWh of energy.

8. **Load Duration Curve** is an annual representation of the hourly average demand data, sorted in a descending order and presented graphically. The load duration curve’s height represents the peak demand or highest level of hourly energy usage for the year. The area under the curve of the load duration curve represents the amount of annual energy required for the year.

9. **Non-Dispatchable Resource** is a resource without the ability to physically control the generation output of that facility. Generally, renewable type resources that only produce electricity when fuel (e.g., wind or sunshine) is available.

**Computer Models**

After developing forecasts of customer demand, L&R tables, and load duration curves of the system, computer modeling of the electric system is often the next step in the planning process. Computer models allow the resource planner to examine how different resource technologies will integrate with the existing fleet to meet the system needs under a range of assumptions from key inputs such as fuel costs. A utility expansion-planning model is specifically designed to construct combinations or portfolios of resources that would meet the capacity and energy needs of the system. The model simulates operation of each of these combinations of resources together with existing generation resources, while keeping track of all associated fixed and variable costs of the entire system.

The computer is needed because it can keep track the thousands of calculations on costs, emissions, operational data, and various other metrics for each of the possible resource portfolios. Models typically have the capability to rank the various portfolios according to user-established
objective functions (e.g., minimization of average rates to customers, or minimization of net present value of revenue requirements).

While this model is a powerful tool that can be used to generate and evaluate thousands of possible resource portfolios, the sheer complexity of these resource evaluations of this magnitude would quickly overwhelm the model’s data storage and computational capabilities unless steps are taken to limit the size of the optimization problem presented to the model at any one time. The number of resource combinations that can be generated each year grows exponentially depending on the number of resources made available to the model.

7.011 - Strategist Model Description

Strategist is a resource planning model specifically designed to determine the least-cost resource mix for a utility system from a prescribed set of resource technologies under given sets of constraints and assumptions. Strategist incorporates a wide variety of expansion planning parameters including alternative generation technologies available to meet future needs, unit capacity sizes, heat rates, fuel costs, LM, conservation programs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan that best suits the utility system being analyzed. Strategist contains four basic modules (load forecast adjustment (“LFA”), generations and fuel (“GAF”), capital expenditure recovery (“CER”), and PROVIEW) that work in concert to simulate the operation of the existing utility system as well as the new resource additions needed to meet future demand growth on the utility system and calculates the costs of serving the system capacity energy needs over the defined study period.

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20 Strategist is one model in a portfolio of modeling tools owned by ABB in Atlanta, Georgia. Xcel Energy has a licensing agreement with ABB for use of the model.
The LFA module is used to represent the utility’s demand and energy forecast. The GAF module represents the operating characteristics of the electric supply system (e.g., generating capacity, heat rate, operating and maintenance, maintenance, equivalent forced outage rate) and works in concert with the LFA to simulate operation of the utility power system. The CER module is used to calculate the revenue requirements for capital expenditures. The PROVIEW module pulls information from all three modules to determine the least-cost balanced demand and supply plan for the utility system under prescribed sets of constraints and assumptions.

7.012 - Costs Included in Strategist

The Strategist model used to develop long-range expansion plans for the SPS electric system includes only a portion of the total electric system cost SPS incurs to provide electric service to our customers. A summary of the costs typically included and those not included in the model are as follows:

Costs Included in Strategist

1. Fuel costs for all electric power supply resources (owned and purchased);
2. Purchased energy costs for all electric power supply resources;
3. Capacity costs of purchased power;
4. VOM costs of purchased power;
5. Capital costs for new electric generation facilities added to meet future load;
6. Electric transmission interconnection and network upgrade cost for new generation;
7. Emissions and emission costs for CO₂, SO₂, and NOₓ;
8. FOM costs for existing and new generation facilities;
9. VOM costs for existing and new generation facilities; and

Costs Not Included in Strategist

1. Remaining book value of existing electric transmission or distribution facilities;
2. Capital costs for planned electric transmission upgrades or distribution facilities;
3. Capital costs for emission control systems; and
4. Administrative and general costs.
7.013 - SPS Unit Retirements

Strategist modeling assumed specific dates that SPS generation would be retired consistent with Table 3-1 (see Section 3, above).

7.014 - Representation of Capital Costs

The Strategist model employs Economic Carrying Charges (“ECC”) in developing and ranking electric resource expansion plans. The present value of the ECC stream of costs is the same as that of the traditional stream of capital revenue requirements over the life of the asset. The 20-year planning period selected for this resource allows the full costs and benefits of 30-year life resources (both SPS-owned resources and purchased power agreements) to be represented in the present value of revenue requirement. Use of ECCs to represent the capital costs of these units allows this truncation of the full costs streams without skewing the validity of the final plan rankings.

7.015 - Other Key Modeling Assumptions

Impacts Due to Change in SPP Regional Fundamentals

SPP power and gas prices are exogenous and treated as inputs to Strategist. Regional impacts due to either surplus and/or shortage of generation capacity including any impacts due to the introduction of the SPP IM (which began March 2014) are reflected in the long-term fundamentally-based forecasts from Cambridge Energy Research Associates (“CERA”) and Petroleum Industry Research Associates (“PIRA”).

Natural Gas Modeling Methodology

Gas prices are developed using a blend of the latest market information (NYMEX futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, IHS CERA, and PIRA
forecasts for Henry Hub. The four sources are combined as a simple average to develop the composite forecast. In the later years, the various sources no longer provide data (i.e., NYMEX goes through 2023 currently). As the source data ends, the latest value is escalated at a gross domestic product/inflation proxy rate to extend the forecast through the end of the modeling period.

For the basis differentials to Henry Hub of the various regional gas hubs needed for the analysis, the settlement price for the ICE-traded basis swap for the relevant hub is used. The last reported year’s profile is extended through the modeling period.

Detailed information regarding the three consultants can be found on their respective websites:

- PIRA: www.pira.com;
- CERA: www.cera.com; and

**High and Low Natural Gas Sensitivity Cases**

For the low and high price cases, base case gas forecast for Henry Hub was adjusted down by 50 percent of the growth (escalation) in the base gas case to represent the low gas case, and adjusted up by 150 percent of the growth in the base gas to represent the high gas case. The basis differentials were left unchanged from the base case.

**Electric Power Price Modeling Methodology**

Power prices are developed from the latest fundamental analyses from Wood Mackenzie and IHS CERA. From their studies, we extract their implied heat rates for the required locations (i.e., back out the gas price to “normalize” the data), and average the heat rates from the two sources to arrive at a composite forecast. Then, the heat rates are multiplied by the composite
natural gas price forecast (as explained in the previous section) to determine the electric prices. This methodology results in power and gas forecasts that are consistent with each other.

**High and Low Power Sensitivity Cases**

The heat rates are kept the same as in the base case, but are then multiplied by the high and low natural gas price forecasts to determine the sensitivity case power prices.

**CO₂ Emission Costs**

Emissions of CO₂ were modeled at $8, $20, $40 per metric ton base year of 2011, escalated at 2.5 percent/year consistent with the final order in NMPRC Case No. 06-00448-UT (*Order Approving Recommended Decision and Adopting Standardized Carbon Emission Costs for Integrated Resource Plans*).

**RPS Requirements**

All modeling assumed SPS’s compliance with respect to the RPS and SPS’s compliance requirements related to meeting the diversity requirements required in the 17.9.572.7.G NMAC.

**Escalation**

The general escalation rate assumed for the base analysis is 2.82 percent. This rate is based on a 40 percent labor and 60 percent non-labor weighted average from Global Insight’s employment cost and producer price U.S. macro forecast.

**Discount Rate**

In evaluating the economics of resource planning decisions and competing resource options, SPS discounts future utility revenue requirement cash flows to determine the lowest cost option, which is normally expressed on a present value of revenue requirement (“PVRR”) basis. These revenue requirements include avoided energy, generation build, capacity purchases, and the tax
deductibility of debt interest. In IRP analyses, revenue requirements normally include the tax
deductibility of debt interest expense and therefore it is appropriate to use the after-tax weighted-
average cost of capital (“WACC”) that incorporates the impact of the deductibility of debt interest
expense.

The discount rate used in developing the 2015 IRP is SPS’s combined jurisdictional
weighted after-tax cost of capital of 7.218 percent, with a tax rate of 36.41 percent.

Table 7-1: Discount Rate Calculation

<table>
<thead>
<tr>
<th>SPS System Weighted</th>
<th>Cost</th>
<th>Capitalization</th>
<th>Pre-Tax WACC</th>
<th>After-Tax WACC</th>
</tr>
</thead>
<tbody>
<tr>
<td>LT Debt</td>
<td>6.57%</td>
<td>47.77%</td>
<td>3.14%</td>
<td>2.00%</td>
</tr>
<tr>
<td>Common Equity</td>
<td>10.00%</td>
<td>52.23%</td>
<td>5.22%</td>
<td>5.22%</td>
</tr>
<tr>
<td>Total</td>
<td>100.00%</td>
<td>8.36%</td>
<td>7.22%</td>
<td></td>
</tr>
</tbody>
</table>

Transmission Costs

Transmission costs were reflected in the modeling by assigning cost estimates for
transmission interconnection and transmission delivery upgrades (i.e., infrastructure) to the generic
resources.

7.02 - A Changing Planning & Regulatory Landscape

SPS is approaching the time period (2018-2028) where it will need to respond to significant
changes in regulatory policy and environmental regulations that could result in: (1) the need to
make large capital investments, which will shape the selection of new generation resources; and (2)
retirement of existing generation resources, ultimately impacting system costs and customer rates.
Some of the key developments and challenges SPS expects to face over the Planning Period will
impact future resource needs, operations, as well as impact the resulting cost of service and rates.
Specifically SPS addresses the:
- Evolving environmental regulations (Section 7.021);
- Evolving SPP IM (7.022);
- Changing customer expectations (7.023);
- Technology advancements that will impact the future of the grid (7.024);
- Tolk Station aquifer depletion (7.025);
- Impacts to the IRP due to an aging generation fleet (3.09); and
- Impacts to the IRP due to high variability system load growth (3.10).

In addition, other variables are also discussed, including tax credits and incentives; gas price forecasts; and RPS-resources acquisition.

This long-term planning landscape addressed in this section foreshadows certain key issues to be addressed in subsequent IRP filings (particularly the 2018 and 2021 IRPs). The planning landscape is also presented so that recommendations and conclusion reached in this 2015 IRP are consistent with the expected future direction of resource planning.

A detailed discussion of the planning landscape is provided below to promote awareness of the major policy issues will need to be addressed in subsequent IRPs. As mentioned earlier, as a result of the significant uncertainty existing today, SPS was unable to accurately capture the impacts of these key policy issues. The 2015 IRP addresses SPS’s near-term resource needs and identifies key policy issues that will shape subsequent IRP content and recommendations and may necessitate changes to the Action Plan in the interim.

**7.021 - Impacts Due to Evolving Environmental Regulations**

Since the development and filing of SPS’s last resource plan filing (2012 IRP), multiple new air, water and waste regulations have been updated and adopted by the EPA. Moreover, regulations for oxides of nitrogen, sulfur dioxide, particulate matter, carbon dioxide, and ozone continue to be updated and are likely to impose added constraints and increase costs at certain power plants. As
discussed in detail in Section 3.08, these regulations (both modified and new) will have a material impact on SPS’s continued ability to provide reliable and affordable power in Texas and New Mexico.

Uncertainty in the environmental regulation arena and the associated range of potential outcomes necessitates a resource plan capable of meeting current rules/regulations yet flexible enough to respond to any significant changes in environmental policy. Clearly, the largest uncertainty relates to the EPA’s CPP Rule, which EPA expects to finalize in August 2015 (see Section 3.08 for a further discussion of the CPP). However, the CPP Rule will likely to be subject to significant legal challenges which would impact the timeline for state compliance. Assuming the CPP Rule is not stayed, states will have one to two years to submit compliance plans to the EPA, and the Rule would go in to effect beginning 2020.

7.022 - Impacts Due to the SPP IM

As discussed earlier (see Section 3.06) insufficient data exists to fully capture the results of the SPP IM, particularly as it relates to SPS’s gas steam power plant cycling, resulting in higher O&M and potentially altering the currently-planned retirement dates. At the same time, resource adequacy is constantly under review by the SPP and it is plausible that the current capacity margin could be reduced below 12 percent in the future.

7.023 - Impacts Due to Shifting Customer Expectations & Preferences

SPS’s large customers have historically been very active in the regulatory process, particularly in their desire for SPS to maintain a competitive rate structure due to the energy-intensive nature of their operations and the significant impact of electric rates on their overall cost of production. These customers are extremely price sensitive and are most likely to take advantage
of new products and services which enables them to reduce their electricity costs. SPS is also hearing from certain of its small/medium commercial accounts and even its residential customers regarding their preference for environmentally clean energy, energy conservation programs, and innovative rate design to encourage shifting of demand/energy usage to off-peak periods. Self-generation (PV) and storage technologies (batteries) could enable customers to bypass their local utility provider. Cost-based alignment of utility-based services and rate design will be crucial (even more than it is today), to ensure that all customers pay for services from which they depend upon and to prevent cost shifting from one customer or customer segment to another customer or group of customers.

7.024 - Impacts Due to Emerging Technologies

The advancement of distributed energy resources such as distributed generation (“DG”), energy storage, and other decentralized devices that supply power to the grid, but are not necessarily energy generators, are contributing to the evolution of the utility industry. SPS does not expect to see significant increases in DG, which we broadly define as generation that is located on or near the site where the output is primarily to be used, interconnected to and operated in parallel with the electric grid, with a total capacity of no more than 10 MW. However, if the cost of solar continues to decrease further relative to the SPS rates, at some point reaching parity with SPS system rates, DG penetration could increase dramatically as compared to where it is today. Generally, customers are increasingly interested in various types of self-generation – specifically solar PV. Growth in solar across all market segments is driven by several forces. Namely, its economics are improving through state and federal incentives and manufacturing advancements. Customers are increasingly interested in new energy choices, including the option to install solar on
their homes and businesses to produce their own energy; and, state and federal policies are promoting solar as a way to reduce GHG emissions and support local economic development.

**7.025 - Impacts Due to Aquifer Reductions**

Tolk Station currently relies exclusively on groundwater for generation cooling. At the time Tolk Station was built, the ground water in the aquifer was believed to be sufficient to accommodate its water needs for the forecasted depreciable life of the facility. However, it is becoming abundantly clear that this assumption is no longer valid. Water in the aquifer has been depleted much faster than what was envisioned at the time Tolk Station was built, and, absent changes in the way the two coal units are operated, Tolk Station could run out of water as soon as 2021. SPS recently acquired certain groundwater rights that will extend the life of Tolk Station, but by itself, this is not a long-term permanent solution. As the aquifer becomes depleted, more and more wells must be drilled in order to maintain the same quantity of water being withdrawn on a daily basis. Whether additional water rights will be available in the future and at what cost are unknown. SPS is also in the process of evaluating horizontal drilling, which has been so successful in the extraction of oil and gas. Alternatives to the purchase of additional water rights are also being examined including the development of a water pipeline using wastewater effluent.

**7.03 - Additional Planning Uncertainties**

The following subsection details areas of additional planning uncertainty during the Planning Period for this IRP. These sections are provided for educational purposes and to further emphasize the complexities of the generation resource planning process.
Tax Credits and Incentives

The current federal production tax credit (“PTC”) for wind resources expired on December 31, 2014. However, if the project commenced construction and a minimum of five percent of total project cost was spent prior to December 31, 2014, and the project is completed by January 1, 2017, the project remains eligible to receive the PTC. Projects are eligible to receive the PTC for a 10-year period. The PTC, which was $23/MWh in 2014, is escalated each year at an inflation factor published by the Internal Revenue Service in April of each year. To date, more than 1,000 MW of contractually purchased wind generation resources on the SPS system have taken advantage of the PTC reducing the energy prices paid by SPS. While the PTC has seen several extensions in the past, the current climate in the U.S. Congress makes another extension uncertain.

The federal investment tax credit (“ITC”) for solar resources is currently 30 percent and will decrease to 10 percent on January 1, 2017.21

Natural Gas

The price of natural gas is a key driver in determining the cost-effectiveness of renewable resources such as wind and solar relative to gas-fired resources. Low gas prices make wind and solar less competitive with gas-fired resources while higher gas prices make them more competitive. Current projections indicate lower forecasted natural gas prices (as compared to the 2009 IRP and 2012 IRP forecasts) (see Figure 7F.1 below); however, these are still forecasts and as such are not guaranteed prices. Factors that could alter the current price outlook include:

- Resistance to local drilling impacts (e.g., noise, air quality, land access, etc.);

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21 Developers can take 30 percent of a project’s total development and construction cost as a tax credit.
• Water issues, including fears over contamination of ground water and fears of pollution associated with the disposal of “produced water” from fracking that could lead to greater regulation; and
• Increased natural gas demand due to faster-than-expected economic growth.

Figure 7F.1: SPS Natural Gas Price Forecasts

7.04 - Renewable Resource Additions

In the 2015 IRP, SPS has assumed full compliance with the RPS requirements of the Renewable Energy Act and the Commission’s Rule 572. However, based on the Reasonable Cost Threshold (“RCT”) presented by SPS in its 2015 RPS, the results (under varying scenarios) indicate that SPS has exceeded the RCT and therefore no new RPS-related resources can be acquired at this time. However: (i) the Commission has not made a determination regarding SPS’s 2016 RPS plan; and (ii) the RCT is very dependent on natural gas prices, which could change future RCT analysis results. Moreover, to the extent renewable energy can be acquired as a cost-effective resource addition, SPS will pursue such additions under a buy-over-time acquisition strategy.
7.05 - Summary of Analysis

*Strategist* was used to simulate system dispatch of the SPS electrical system and economically optimize the resource additions, subject to the constraints and assumptions identified above. *Strategist* was also relied upon to capture the incremental impact of various resource additions, removals, or replacements. Following is a discussion of low, base, and high load forecasts, optimized model runs, and delta case scenarios.

**Base Case L&R & Low/High L&R Sensitivities**

An unfilled L&R representing the base load forecast, along with separate line items showing the resource need based upon the low and high load forecast sensitivities are shown in Table 5.2 (see Section 5, above).

7.06 - *Strategist* Optimized Model Results

*Strategist* was first allowed to economically optimize resource additions, based upon the base load forecast. As part of this optimization, carbon was assumed to be at zero cost. The resulting expansion plan from the “Optimized Base Case” is shown below in Table 7.2 (below).

Next, the model was subjected to certain stress tests (or sensitivities) in order to ascertain the robustness of the selected portfolio in the “Optimized Base Case”. Sensitivities included high and low fuel/power price assumptions, and varying carbon price assumptions. Specifically, *Strategist* was allowed to re-dispatch under these varying assumptions (for the price of natural gas (low & high), carbon prices ($8/ton, $20/ton, and $40/ton) and allowed to re-optimize under the low load forecast and under the high load forecast). In addition, SPS determined the break-even levelized cost for solar ($50.49/MWh) and wind ($43.08/MWh), based upon the system avoided energy cost for each resource type. A levelized cost (from a request for proposals (“RFP”) respondent or self-
build resource) at or below the above amounts would provide economic savings to ratepayers. The results of the base, high and low optimized expansion plans are shown in Table 7-2, below. Table 7-3 below provides the PVRR of each of the above expansion plans plus certain the sensitivities that were run relative to the base case.
<table>
<thead>
<tr>
<th>Year</th>
<th>Auction Number</th>
<th>Retired</th>
<th>Retired</th>
<th>Federal Library</th>
<th>Federal Library</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2021</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2022</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2023</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2024</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2025</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2026</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>2027</td>
<td>CARRYOVER 2</td>
<td>27</td>
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<td>N/A</td>
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</tr>
<tr>
<td>2028</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
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</tr>
<tr>
<td>2029</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>2030</td>
<td>CARRYOVER 2</td>
<td>27</td>
<td>27</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table 7-2: Optimized Model Results
Table 7-3: PVRR of Identified Model Runs

<table>
<thead>
<tr>
<th>Case</th>
<th>PVRR (2015-2054)</th>
<th>PVRR DeltaS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>$27,411,750</td>
<td>$0</td>
</tr>
<tr>
<td>High Gas</td>
<td>$32,768,444</td>
<td>$5,356,694</td>
</tr>
<tr>
<td>Low Gas</td>
<td>$23,990,772</td>
<td>-$3,420,977</td>
</tr>
<tr>
<td>High CO2</td>
<td>$44,316,285</td>
<td>$16,904,536</td>
</tr>
<tr>
<td>Med CO2</td>
<td>$36,225,358</td>
<td>$8,813,608</td>
</tr>
<tr>
<td>Low CO2</td>
<td>$31,022,925</td>
<td>$3,611,175</td>
</tr>
<tr>
<td>High Load</td>
<td>$33,839,333</td>
<td>NA</td>
</tr>
<tr>
<td>Low Load</td>
<td>$22,484,956</td>
<td>NA</td>
</tr>
</tbody>
</table>
Section 8. PUBLIC ADVISORY PROCESS

Pursuant to the IRP Rule (17.7.3.9.H NMAC), SPS was required to begin planning for the 2015 IRP filing a minimum of one year prior to the filing date; therefore, consistent with the IRP Rule, invitations and notices for the initial meeting, held on July 15, 2014, were sent and published a minimum of 30 days prior to the first meeting. To ensure broad public input, SPS invited the Utility Division Staff of the Commission (“Staff”), as well as the interveners in its most recent general rate case, renewable energy, and EE proceedings. The invited parties cover multiple interest areas (e.g., residential, environmental, industrial and consumer advocacy) to ensure varied opinions and perspectives.

SPS published notice of the first meeting on or around June 15, 2014, in the Albuquerque Journal, Artesia Daily Press, Carlsbad Current-Argus, Clovis News Journal, Hobbs News-Sun, Portales News-Tribune, Roswell Daily Record, and Quay County Sun newspapers. These newspapers cover the general circulation of every county in New Mexico that SPS serves. SPS also provided notice with a one-time bill insert to all New Mexico retail customers during the June-July 2014 billing period. Copies of the invitation, public notice, and bill insert are included in Appendix H.

SPS held the first Public Advisory Process meeting on July 15, 2014 in Santa Fe, New Mexico. This meeting was also available via public webinar video conferencing service. Subsequent meetings occurred (by the use of webinar internet meetings and conference lines) over the subsequent 12 months, where various subjects were presented and discussed (see the table below). In total, five meetings were held.
SPS provided adequate notice and an agenda of topics to be discussed before each meeting. SPS experienced low public participation at all five public advisory meetings. Commonly, attendance included one or two members from Staff, one or two renewable generation developers, and a representative from one environmental agency. SPS did have a representative from another New Mexico utility attend the initial July 2014 meeting. Very few questions were fielded by SPS representatives throughout the Public Advisory Process.

A complete timeline of the Public Advisory meetings and summary of subject matters that were discussed at each of these meeting is presented in Table 8-1. A complete record showing the content presented at each of these meetings is included in Appendix I.

Table 8-1: Public Advisory Process Timeline and Subject Areas

<table>
<thead>
<tr>
<th>Meeting Date</th>
<th>Topics Discussed</th>
</tr>
</thead>
<tbody>
<tr>
<td>July 15, 2014</td>
<td>SPS System Overview</td>
</tr>
<tr>
<td></td>
<td>2014 RPS Filing Update</td>
</tr>
<tr>
<td></td>
<td>Overview of 2012 IRP</td>
</tr>
<tr>
<td></td>
<td>Discussion of SE New Mexico Load Growth</td>
</tr>
<tr>
<td>September 25, 2014</td>
<td>SPS Solar RFP</td>
</tr>
<tr>
<td></td>
<td>Environment 101 Update</td>
</tr>
<tr>
<td></td>
<td>EPA - Clean Power Plan</td>
</tr>
<tr>
<td>January 15, 2015</td>
<td>Gas &amp; Power Markets</td>
</tr>
<tr>
<td></td>
<td>Coal Supply</td>
</tr>
<tr>
<td></td>
<td>DSM</td>
</tr>
<tr>
<td></td>
<td>Load Forecasting</td>
</tr>
<tr>
<td>April 16, 2015</td>
<td>Review SPS L&amp;R table</td>
</tr>
<tr>
<td></td>
<td>Overview of Key SPS IRP Issues</td>
</tr>
<tr>
<td></td>
<td>Retirement Plan for SPS Generation Fleet</td>
</tr>
<tr>
<td></td>
<td>SPS Coal Generation Strategy</td>
</tr>
<tr>
<td>June 30, 2015</td>
<td>SPS Short-term Resource Planning</td>
</tr>
<tr>
<td></td>
<td>SPS Long-term Resource Planning</td>
</tr>
</tbody>
</table>
Section 9. ACTION PLAN

9.01 - SPS Action Plan for 2016-2019

For a detailed presentation of SPS’s plans for the Action Plan Period, please refer to Table 7.2.

The L&R table indicates that SPS has adequate generating capacity for the period 2016-2019, with the exception of 2018, where a small capacity need of 25 MW is projected. Beginning in 2019, Plant X Unit 1 and Cunningham Unit 1 are currently scheduled for retirement. However, due to multiple and significant long-term resource planning uncertainties discussed earlier, SPS will continue to study the feasibility and timing for retiring SPS generation, including the planned 2019 retirement of Plant X Unit 1 and Cunningham Unit 1.

Since filing of the 2012 IRP, SPS has, and continues to experience, significant load growth in southeast New Mexico, driven primarily from an increase in oil and natural gas production. The increased load growth is occurring in the most isolated area of SPS, as well as the SPP footprint. This results in the need for location-specific generation and transmission planning solutions. In South East New Mexico, high load growth in an area with limited existing infrastructure, including generation and transmission facilities, have resulted in high LMPs in that area, which are not fully expected to be relieved during the Action Plan timeframe.

Also, subsequent to the 2012 IRP filing, SPS began receiving indications that PV solar energy prices were dropping significantly from the prices that were known in the 2012 IRP filing. At the time SPS filed its 2012 IRP, PV solar energy prices were around $130/MWh. Because of these potential significant prices decreases, as well as the increasing load in southeast New Mexico, in September 2014, SPS issued an RFP seeking up to 200 MW of PV solar energy. The RFP
resulted in SPS successfully negotiating two 70 MW PPAs, to be located in Chaves County, New Mexico, and are currently pending before the Commission in Case No. 15-00083-UT. The levelized prices for these currently-pending PPAs are $41.55 and $42.08/MWh, respectively, and are expected to provide significant economic savings to ratepayers.

As discussed in Section 7, the base plan shows the need for a CT by 2020. However, if higher load growth occurs (relative to the base load forecast) during the Action Plan period or other uncertainties materialize such as the loss of existing generation, SPS has the option to accelerate the CT for a commercial operation date earlier than 2020, which would require a CCN filing during the Action Plan period.

9.02 - Status Report

In following with the conclusions from the 2012 IRP filing, SPS has acquired the then-pending PPA where SPS was requesting the Commission’s approval for an additional 200 MW from Calpine Energy Services, L.P. for the period June 2014 through May 2019. That acquisition was approved January 15, 2013 in Case No. 12-00235-UT. SPS also contemplated the need for approximately an additional 25 MW of solar and 3-4 MW of “other” resources. SPS determined in the 2013 RPS filing (Case No. 13-00222-UT) that adding the incremental renewable resources would exceed the RCT under 17.9.572 NMAC and, therefore, did not seek the additional 25 MW of solar and 3-4 MW of “other” renewables.