BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA

Application Of Southern California Edison Company (U 338-E) For Approval of its 2016 Rate Design Window Proposals.

A.16-09-003
(Filed September 1, 2016)

SOUTHERN CALIFORNIA EDISON COMPANY’S (U 338-E)
NOTICE OF EX PARTE COMMUNICATION

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Dated: July 5, 2017
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA

Application Of Southern California Edison
Company (U 338-E) For Approval of its 2016
Rate Design Window Proposals.

(Southern California Edison Company's (U 338-E)
NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Rules of Practice and Procedure of the California Public
Utilities Commission (“Commission”), Southern California Edison Company (“SCE”) hereby
gives notice of the following ex parte communications.

On June 29, 2017, SCE’s Russell Garwacki, Director of Pricing Design and Research,
gave a presentation on a panel at the Rutgers Center for Research in Regulated Industries
(“CRRI”), Advanced Workshop in Regulation and Competition, at the Hyatt Regency in
Monterey, California. The panel lasted from approximately 10:20 a.m. to 11:50 a.m.
Mr. Garwacki provided an overview of SCE’s Real Time Pricing program and discussed
small customer Critical Peak Pricing load quantification used in SCE’s Rate Design Window
application. Mr. Garwacki also discussed potential changes to the Real Time Pricing rate
structure. In addition, the written presentation attached hereto as Appendix A was presented
during the panel, and the white paper attached hereto as Appendix B was available to
attendees for download before the conference. Mr. Scott Murtishaw, a Commission employee
who identified himself as a “decisionmaker” under the Commission’s *ex parte* rules, was an attendee at the conference.

On June 30, 2017, SCE’s Paul Nelson, Senior Project Manager, and Benjamin Baker, Senior Financial Analyst, gave a presentation on a panel at the Rutgers CRRI, Advanced Workshop in Regulation and Competition, at the Hyatt Regency in Monterey, California. The presentation lasted from approximately 9:10 a.m. to 9:30 a.m., with a related question and answer period from approximately 10:00 a.m. to 10:30 a.m. Mr. Nelson and Mr. Baker described a methodology to calculate a loss of load expectation (“LOLE”) that can be used to allocate generation capacity between peak and ramping needs. As the amount of renewables increases, the need for ramping resources is also expected to increase. The loss of load expectation methodology can inform rate design as an input to develop time-of-use costing periods to send a price signal to customers to reduce demand during peak or ramping periods. During the question and answer period, Mr. Garwacki asked whether San Diego Gas & Electric Company compares its gross solar output data to PV Watts modeled data. Mr. Garwacki also suggested that a current electric vehicle rebate program could provide more information about load profiles associated with electric vehicle charging, because those customers have been hard to identify in the past. In addition, the written presentation attached hereto as Appendix C was presented during the panel, and the white paper attached hereto as Appendix D was available to attendees for download before the conference. Mr. Scott Murtishaw, a Commission employee who identified himself as a “decisionmaker” under the Commission’s *ex parte* rules, was an attendee at the conference.
To receive a copy of this \textit{ex parte} notice, please contact:

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Respectfully submitted,

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By: Russell A. Archer

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July 5, 2017
Appendix A
Real Time Pricing (RTP) AT SCE
Real Time Pricing (RTP) at SCE

Russell Garwacki*

*The views expressed in this presentation are the author’s and do not necessarily reflect the views of Southern California Edison

CRRI Western Conference
Monterey, CA
June 29, 2017
Background of RTP at SCE

- SCE initially launched a RTP pilot in 1987 with 10 accounts. During 1993, the number of RTP customers increased from 15 to 34.
- Currently, there are around 150 RTP accounts.
  - Before 2009, only large accounts with demand larger than 500 kW (TOU-8) were enrolled in RTP;
  - Agricultural and pumping accounts (TOU-PA-2 and TOU-PA-3) started to enroll in RTP from 2010;
  - C&I Accounts with demand between 200 kW and 500 kW (TOU-GS-3) accounts from 2013;
  - Smaller C&I accounts with demand less than 20 kW (GS-1) and between 20 kW and 200 kW (GS-2) from 2015
RTP vs. Standard Rate – Generation Cost Recovery

- TOU-8 basic rate structure has both time differentiated energy charges and time differentiated demand charges.
- RTP recovers generation capacity costs from energy charges rather than demand charges.

<table>
<thead>
<tr>
<th></th>
<th>TOU-8 (Standard Rate)</th>
<th>RTP Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Energy Charge - $kWh/Meter/Month</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer Season - On-Peak</td>
<td>0.07072</td>
<td>Varied by Hour</td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>0.04730</td>
<td></td>
</tr>
<tr>
<td>Off-Peak</td>
<td>0.03165</td>
<td></td>
</tr>
<tr>
<td>Winter Season - On-Peak</td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>0.04579</td>
<td></td>
</tr>
<tr>
<td>Off-Peak</td>
<td>0.03645</td>
<td></td>
</tr>
<tr>
<td><strong>Demand Charge - $/kW of Billing Demand/Meter/Month</strong></td>
<td>\text{Time Related}</td>
<td>\text{0}</td>
</tr>
<tr>
<td>Summer Season - On-Peak</td>
<td>18.97</td>
<td></td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>3.58</td>
<td></td>
</tr>
<tr>
<td>Winter Season - On-Peak</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>0.00</td>
<td></td>
</tr>
</tbody>
</table>

The above tables only show the generation portion of the bill, because the delivery portion of bills are very similar for TOU-8 (standard) rate and RTP rate. Both rates have facility related demand charge for the delivery service.
RTP Current Rates and Schedules

- There are currently 9 different pricing schedules for RTP customers. Pricing schedules are based on seasonal day types and the prior day’s Downtown Los Angeles maximum temperature.

- Same basic structure for over 25 years where LOLE derived capacity values are added to estimated hourly energy prices.

<table>
<thead>
<tr>
<th>Current TOU-8-SEC RTP Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>HOUR ENDING @ PST</strong></td>
</tr>
<tr>
<td>1 a.m.</td>
</tr>
<tr>
<td>2 a.m.</td>
</tr>
<tr>
<td>3 a.m.</td>
</tr>
<tr>
<td>4 a.m.</td>
</tr>
<tr>
<td>5 a.m.</td>
</tr>
<tr>
<td>6 a.m.</td>
</tr>
<tr>
<td>7 a.m.</td>
</tr>
<tr>
<td>8 a.m.</td>
</tr>
<tr>
<td>9 a.m.</td>
</tr>
<tr>
<td>10 a.m.</td>
</tr>
<tr>
<td>11 a.m.</td>
</tr>
<tr>
<td>12 noon</td>
</tr>
<tr>
<td>1 p.m.</td>
</tr>
<tr>
<td>2 p.m.</td>
</tr>
<tr>
<td>3 p.m.</td>
</tr>
<tr>
<td>4 p.m.</td>
</tr>
<tr>
<td>5 p.m.</td>
</tr>
<tr>
<td>6 p.m.</td>
</tr>
<tr>
<td>7 p.m.</td>
</tr>
<tr>
<td>8 p.m.</td>
</tr>
<tr>
<td>9 p.m.</td>
</tr>
<tr>
<td>10 p.m.</td>
</tr>
<tr>
<td>11 p.m.</td>
</tr>
<tr>
<td>Midnight</td>
</tr>
</tbody>
</table>

# of Days: 4 7 16 23 36 47 57

Southern California Edison
RTP Trigger

- The purpose of RTP is to reduce the peak demand. Therefore, the trigger has to be highly correlated with the system load.
- The prior day’s Downtown Los Angeles maximum temperature is highly correlated with the system load. This temperature trigger is also easy to understand and simple to implement.

<table>
<thead>
<tr>
<th>Day Type</th>
<th>Prior Day's Downtown Los Angeles Site Maximum Temperature</th>
<th>Same Day's Downtown Los Angeles Site Maximum Temperature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Workdays</td>
<td>0.79</td>
<td>0.87</td>
</tr>
<tr>
<td>All Days</td>
<td>0.74</td>
<td>0.80</td>
</tr>
<tr>
<td>Annual</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Workdays</td>
<td>0.67</td>
<td>0.70</td>
</tr>
<tr>
<td>All Days</td>
<td>0.63</td>
<td>0.66</td>
</tr>
</tbody>
</table>

**Correlation between SCE's Daily System Peak (MW) and Temperature**

**Scatter Plot**

Observations: 684
Correlation: 0.7895
p-Value: 9E-147

**Summer Workdays: 2008 - 2015**
Methods to Measure the Load Impact

- Computation of extremely hot summer weekday, very hot summer weekday, and mild summer weekday load profiles.
  - Calculated the average load profile for different day types for each customer.
  - Summed the average extremely hot, very hot, and mild summer weekday load profile for all customers.

- Average load drop = average load of extremely hot summer weekday – average load of mild summer weekday for the highest priced hours.
  - The two highest priced hours occurred at 4:00 p.m. and 5:00 p.m. hour ending PST.
  - We compared these 2 schedules because they were the highest and lowest priced RTP schedules in summer.
## SCE’s RTP Load Impact – Excluding Largest Account

<table>
<thead>
<tr>
<th>Year</th>
<th>Average Number of Accounts</th>
<th>Average Number of TOU-8 Accounts (Demand Larger than 500 kW)</th>
<th>Avg Load (MW) for Hour 4 p.m. and 5 p.m. (PST Hour Ending)</th>
<th>Extremely Hot Summer Weekday Load Impact</th>
<th>Very Hot Summer Weekday Load Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>EXTREMELY HOT SUMMER WEEKDAY (&gt;=95)</td>
<td>MW</td>
<td>%</td>
</tr>
<tr>
<td>2008</td>
<td>77</td>
<td>77</td>
<td>54</td>
<td>59</td>
<td>58</td>
</tr>
<tr>
<td>2009</td>
<td>83</td>
<td>83</td>
<td>43</td>
<td>40</td>
<td>48</td>
</tr>
<tr>
<td>2010</td>
<td>92</td>
<td>87</td>
<td>40</td>
<td>43</td>
<td>53</td>
</tr>
<tr>
<td>2011</td>
<td>128</td>
<td>97</td>
<td>44</td>
<td>40</td>
<td>63</td>
</tr>
<tr>
<td>2012</td>
<td>125</td>
<td>96</td>
<td>NA</td>
<td>50</td>
<td>69</td>
</tr>
<tr>
<td>2013</td>
<td>123</td>
<td>94</td>
<td>41</td>
<td>55</td>
<td>89</td>
</tr>
<tr>
<td>2014</td>
<td>136</td>
<td>100</td>
<td>54</td>
<td>64</td>
<td>97</td>
</tr>
<tr>
<td>2015</td>
<td>140</td>
<td>88</td>
<td>41</td>
<td>52</td>
<td>86</td>
</tr>
<tr>
<td>2016</td>
<td>141</td>
<td>84</td>
<td>42</td>
<td>55</td>
<td>73</td>
</tr>
</tbody>
</table>

- The overall load reduction for RTP customers is heavily impacted by one large customer, which could make up to 50% of total RTP load.
- Load impact increased drastically in 2010 since the enrollment of another large account in 2010, which consistently dropped a large amount of load.
- Consistent reductions on very hot days indicate customer acceptances of load reduction on very hot days as well.
Load Profiles - Excluding Largest Account

Average load profile of 2014 to 2016

RTP Load Profiles

Current TOU-8-SEC-RTP Generation Prices
RTP load profiles are very different from non-RTP load profiles. In general, average RTP profiles peak in the morning and dip in the afternoon.

Non-RTP loads are flatter but appear to be temperature sensitive as energy consumption is higher on hot days than on mild days.

See load profiles of other rate groups in the backup slides.
Nexant’s RTP Study

- Nexant used regression model to measure the RTP load impact.
  - Variables: price, price ratio, hour, day type, temperature, etc.
- Nexant’s report measured the average load drop for longer hours from 1 p.m. to 6 p.m. instead of the two-hour window in this study.

<table>
<thead>
<tr>
<th>Year</th>
<th>System Peak Day Day Type</th>
<th>Nexant’s Load Impact on System Peak Day</th>
<th>SCE’s method</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>Extremely Hot Summer Weekday</td>
<td>15.50%</td>
<td>17%</td>
</tr>
<tr>
<td>2011</td>
<td>Extremely Hot Summer Weekday</td>
<td>15.80%</td>
<td>20%</td>
</tr>
<tr>
<td>2012</td>
<td>Very Hot Summer Workday</td>
<td>14.30%</td>
<td>10%</td>
</tr>
<tr>
<td>2014</td>
<td>Very Hot Summer Workday</td>
<td>16.90%</td>
<td>17%</td>
</tr>
<tr>
<td>2015</td>
<td>Extremely Hot Summer Weekday</td>
<td>32.80%</td>
<td>43%</td>
</tr>
</tbody>
</table>

- The two methods show similar results.
Three industry groups that show significant load drop during high-priced hours are: Agriculture, Mining & Construction; Manufacturing; Wholesale, Transport, other Utilities.

Penetration of RTP in the three industries is not high among the large C&I (>500 kW) accounts.

For the large C&I (>500 kW) accounts, RTP rates save them around 15% compared to the standard TOU-8 rates.

There would appear to be more potential to further market the RTP program to large C&I accounts.
Critical Peak Pricing (CPP) Rate Structure

- SCE currently calls 12 CPP events per year.
- CPP event energy charge is around $1.3/ kWh. Customers get bills credits during the summer months.
- SCE defaulted accounts with demand higher than 200 kW onto CPP from Oct 2009.
  - Around 7,000 accounts were defaulted.
  - Customers can opt out of CPP at anytime.
  - Recent customer count shows that around 24% defaulted accounts stayed on CPP.
Critical Peak Pricing (CPP) – SCE results (from Nexant, Christensen Associates Energy Consulting)

- Load impact for 2008 and 2009 were from opt-in CPP accounts; Load impact from 2010 to 2015 were mainly from default CPP accounts.
- The commission’s preference is to default all customers <200 kW to CPP.
- See the references in the backup slides

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of CPP Accounts</th>
<th>Estimated Reference Load (MW)</th>
<th>Observed Load (MW)</th>
<th>Estimated Load Impact (MW)</th>
<th>Load Impact (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>201</td>
<td>60</td>
<td>45</td>
<td>-15</td>
<td>-26.0%</td>
</tr>
<tr>
<td>2009</td>
<td>476</td>
<td>130</td>
<td>106</td>
<td>-25</td>
<td>-18.9%</td>
</tr>
<tr>
<td>2010</td>
<td>4,100</td>
<td>1077</td>
<td>1047</td>
<td>-31</td>
<td>-2.8%</td>
</tr>
<tr>
<td>2011</td>
<td>3,000</td>
<td>615</td>
<td>580</td>
<td>-35</td>
<td>-5.7%</td>
</tr>
<tr>
<td>2012</td>
<td>2,508</td>
<td>554</td>
<td>521</td>
<td>-33</td>
<td>-5.9%</td>
</tr>
<tr>
<td>2013</td>
<td>2,495</td>
<td>613</td>
<td>577</td>
<td>-36</td>
<td>-5.8%</td>
</tr>
<tr>
<td>2014</td>
<td>2,670</td>
<td>594</td>
<td>565</td>
<td>-30</td>
<td>-5.0%</td>
</tr>
<tr>
<td>2015</td>
<td>2,667</td>
<td>582</td>
<td>553</td>
<td>-29</td>
<td>-5.0%</td>
</tr>
</tbody>
</table>
Default Small C&I onto CPP: Load Impact Estimation

**Table 4-11: SMB Default CPP Ex Post Load Impact Estimates by Customer Size**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>By Demand Size</td>
<td>20 kW to 200 kW</td>
<td>21,503</td>
<td>21.6</td>
<td>21.4</td>
<td>0.2</td>
<td>4.3</td>
<td>0.9%</td>
<td>92.1</td>
<td>Yes</td>
</tr>
<tr>
<td>Less than 20 kW</td>
<td>127,279</td>
<td>2.3</td>
<td>2.3</td>
<td>0.0</td>
<td>1.5</td>
<td>0.5%</td>
<td>92.7</td>
<td>No</td>
<td></td>
</tr>
</tbody>
</table>

* Summations across segmentation categories may not equal totals presented for all customers on the average event day (Table 4-1). Sector specific estimates required estimation of separate difference-in-differences models and can result on rounding errors.

- The load impact was minimal for small commercial and industrial (C&I) accounts that were defaulted onto CPP.
- PG&E’s CPP event energy charge was around 85 cents/ kWh.

**Table VI-15**

<table>
<thead>
<tr>
<th>Customer Group</th>
<th>PG&amp;E Load Impacts per Account</th>
<th>SCE Approx. Accounts Impacted by Default CPP</th>
<th>Estimated Enrollment Rate After Customer Opt-Outs</th>
<th>SCE Illustrative Aggregate Load Impacts</th>
<th>CPP MW as % of SCE’s Total CPP Load Impacts</th>
<th>CPP MW as % of SCE’s Total DR Portfolio</th>
</tr>
</thead>
<tbody>
<tr>
<td>C&amp;I 20-200 kW</td>
<td>0.200 kW</td>
<td>67,000</td>
<td>24%</td>
<td>3.2 MW</td>
<td>11.0%</td>
<td>0.22%</td>
</tr>
<tr>
<td>C&amp;I less than 20 kW</td>
<td>0.012 kW</td>
<td>450,000</td>
<td>24%</td>
<td>1.3 MW</td>
<td>4.5%</td>
<td>0.09%</td>
</tr>
</tbody>
</table>

- Using PG&E’s results for small C&Is, SCE’s estimated load drop will be 3.2 MW for C&I 20-200 kW and 1.3 MW for C&I less then 20 kW.

Table 4-11: George, S. et al., 2016. 2015 Load Impact Evaluation of California’s Statewide Nonresidential Critical Peak Pricing Program

Table VI-15: Testimony of Southern California Edison Company in Support of its Application For Approval of its 2016 Rate Design Window Proposals
Proposed RTP Rates and Schedules

- Influx of renewables portfolio standard (RPS) energy changes the cost curve. Because of the increasing penetration of solar production, lowest prices occur in the middle of the day instead of previously at night; highest prices occur in the early evening instead of in the late afternoon.

- In the 2016 Rate Design Window filing, SCE proposed to condense the pricing schedules to simplify the RTP rate structure and increase program enrollment.

<table>
<thead>
<tr>
<th>Hour of Day</th>
<th>Hot Summer (≥90)</th>
<th>Medium Summer (81-90)</th>
<th>Mild Summer (≤80)</th>
<th>High Cost Winter (≥90)</th>
<th>Low Cost Winter (≤70)</th>
<th>High Cost Weekend (≥90)</th>
<th>Low Cost Weekend (≤70)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 a.m.</td>
<td>0.04208</td>
<td>0.04164</td>
<td>0.04112</td>
<td>0.04198</td>
<td>0.04123</td>
<td>0.04126</td>
<td>0.04098</td>
</tr>
<tr>
<td>2 a.m.</td>
<td>0.03999</td>
<td>0.03919</td>
<td>0.03913</td>
<td>0.04072</td>
<td>0.04015</td>
<td>0.04103</td>
<td>0.03999</td>
</tr>
<tr>
<td>3 a.m.</td>
<td>0.03932</td>
<td>0.03877</td>
<td>0.03885</td>
<td>0.03984</td>
<td>0.03992</td>
<td>0.04086</td>
<td>0.03976</td>
</tr>
<tr>
<td>4 a.m.</td>
<td>0.03899</td>
<td>0.03873</td>
<td>0.03890</td>
<td>0.03939</td>
<td>0.03889</td>
<td>0.03966</td>
<td>0.03970</td>
</tr>
<tr>
<td>5 a.m.</td>
<td>0.03941</td>
<td>0.03890</td>
<td>0.03941</td>
<td>0.04057</td>
<td>0.04024</td>
<td>0.04069</td>
<td>0.03970</td>
</tr>
<tr>
<td>6 a.m.</td>
<td>0.04105</td>
<td>0.04046</td>
<td>0.04059</td>
<td>0.04230</td>
<td>0.04194</td>
<td>0.04105</td>
<td>0.04036</td>
</tr>
<tr>
<td>7 a.m.</td>
<td>0.0407</td>
<td>0.04259</td>
<td>0.04036</td>
<td>0.04855</td>
<td>0.04684</td>
<td>0.04184</td>
<td>0.04023</td>
</tr>
<tr>
<td>8 a.m.</td>
<td>0.03966</td>
<td>0.03877</td>
<td>0.03719</td>
<td>0.04315</td>
<td>0.04614</td>
<td>0.03899</td>
<td>0.03830</td>
</tr>
<tr>
<td>9 a.m.</td>
<td>0.03666</td>
<td>0.03655</td>
<td>0.03397</td>
<td>0.03847</td>
<td>0.03859</td>
<td>0.03235</td>
<td>0.02801</td>
</tr>
<tr>
<td>10 a.m.</td>
<td>0.03618</td>
<td>0.03568</td>
<td>0.03391</td>
<td>0.03572</td>
<td>0.03605</td>
<td>0.02947</td>
<td>0.02291</td>
</tr>
<tr>
<td>11 a.m.</td>
<td>0.03596</td>
<td>0.03572</td>
<td>0.03552</td>
<td>0.03489</td>
<td>0.03489</td>
<td>0.03085</td>
<td>0.02325</td>
</tr>
<tr>
<td>12 noon</td>
<td>0.0378</td>
<td>0.03670</td>
<td>0.03440</td>
<td>0.03412</td>
<td>0.03405</td>
<td>0.02143</td>
<td>0.02014</td>
</tr>
<tr>
<td>1 p.m.</td>
<td>0.03753</td>
<td>0.03770</td>
<td>0.03769</td>
<td>0.03775</td>
<td>0.03737</td>
<td>0.03232</td>
<td>0.02099</td>
</tr>
<tr>
<td>2 p.m.</td>
<td>0.03891</td>
<td>0.03978</td>
<td>0.03818</td>
<td>0.03936</td>
<td>0.03992</td>
<td>0.03323</td>
<td>0.02099</td>
</tr>
<tr>
<td>3 p.m.</td>
<td>0.04029</td>
<td>0.04244</td>
<td>0.03769</td>
<td>0.04367</td>
<td>0.04099</td>
<td>0.03066</td>
<td>0.02445</td>
</tr>
<tr>
<td>4 p.m.</td>
<td>0.04055</td>
<td>0.04558</td>
<td>0.03919</td>
<td>0.04370</td>
<td>0.03752</td>
<td>0.03829</td>
<td>0.03013</td>
</tr>
<tr>
<td>5 p.m.</td>
<td>0.06097</td>
<td>0.05094</td>
<td>0.04120</td>
<td>0.04752</td>
<td>0.05328</td>
<td>0.04146</td>
<td>0.04736</td>
</tr>
<tr>
<td>6 p.m.</td>
<td>0.25959</td>
<td>0.07631</td>
<td>0.05518</td>
<td>0.19036</td>
<td>0.11059</td>
<td>0.12770</td>
<td>0.07011</td>
</tr>
<tr>
<td>7 p.m.</td>
<td>3.75490</td>
<td>0.22238</td>
<td>0.12993</td>
<td>0.11052</td>
<td>0.12117</td>
<td>0.16674</td>
<td>0.11876</td>
</tr>
<tr>
<td>8 p.m.</td>
<td>2.74345</td>
<td>0.13441</td>
<td>0.06792</td>
<td>0.06521</td>
<td>0.06733</td>
<td>0.08667</td>
<td>0.06384</td>
</tr>
<tr>
<td>9 p.m.</td>
<td>0.57124</td>
<td>0.07432</td>
<td>0.06425</td>
<td>0.05917</td>
<td>0.05786</td>
<td>0.06544</td>
<td>0.05442</td>
</tr>
<tr>
<td>10 p.m.</td>
<td>0.13386</td>
<td>0.05954</td>
<td>0.05935</td>
<td>0.05232</td>
<td>0.05196</td>
<td>0.05359</td>
<td>0.05143</td>
</tr>
<tr>
<td>11 p.m.</td>
<td>0.0527</td>
<td>0.05005</td>
<td>0.04946</td>
<td>0.04907</td>
<td>0.04907</td>
<td>0.04781</td>
<td>0.04781</td>
</tr>
<tr>
<td>Midnight</td>
<td>0.0481</td>
<td>0.04430</td>
<td>0.04299</td>
<td>0.04352</td>
<td>0.04276</td>
<td>0.04369</td>
<td>0.04264</td>
</tr>
</tbody>
</table>
SCE RTP Tariff’s Future

- Relationship between peak temperature and hourly prices may change as the belly of the duck curve deepens. More ramping capacity will be needed and priced accordingly in CAISO markets.

- SCE is exploring the use of Cooling Degree Days and/or spot natural gas price instead of purely temperature as the RTP price trigger.

- Separate Matinee triggers should be explored.

- SCE is also looking at using actual SP-15 Day-Ahead Market Prices plus a capacity adder.
Conclusion

- RTP customers show significant amount of load drop during high-priced hours. Customers respond well to the temperature trigger that is transparent and easy-to-follow.
- SCE would get far more load drop from a few large RTP accounts than all of small customers that will be defaulted onto CPP.
- RTP structure has the flexibility to offer low pricing during middle of the day to encourage consumption when over supply is possible.
- There would appear to be more Demand Response potential to market the opt-in RTP to larger customers in lieu of default CPP to smaller customers.
SCE’s Real-Time Pricing Day Types (2008-2016)

- The number of extremely hot days in each year were in the range of 0 to 6 days; the number of very hot days were in the range of 1 to 8 days. 2015 had the most hot summer workdays.
SCE’s RTP Load Impact

<table>
<thead>
<tr>
<th>Year</th>
<th>Average Number of Accounts</th>
<th>Average Number of TOU-8 Accounts (Demand Larger than 500 kW)</th>
<th>Avg Load (MW) for Hour 4 p.m. and 5 p.m. (PST Hour Ending)</th>
<th>Extremely Hot Summer Weekday Load Impact</th>
<th>Very Hot Summer Weekday Load Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>EXTREMELY HOT SUMMER WEEKDAY (&gt;=95)</td>
<td>VERY HOT SUMMER WEEKDAY (91-94)</td>
<td>MILD SUMMER WEEKDAY (&lt;=80)</td>
</tr>
<tr>
<td>2008</td>
<td>78</td>
<td>78</td>
<td>113</td>
<td>134</td>
<td>134</td>
</tr>
<tr>
<td>2009</td>
<td>84</td>
<td>84</td>
<td>116</td>
<td>119</td>
<td>125</td>
</tr>
<tr>
<td>2010</td>
<td>93</td>
<td>88</td>
<td>101</td>
<td>108</td>
<td>121</td>
</tr>
<tr>
<td>2011</td>
<td>129</td>
<td>98</td>
<td>107</td>
<td>102</td>
<td>133</td>
</tr>
<tr>
<td>2012</td>
<td>126</td>
<td>97</td>
<td>NA</td>
<td>116</td>
<td>129</td>
</tr>
<tr>
<td>2013</td>
<td>124</td>
<td>95</td>
<td>110</td>
<td>123</td>
<td>157</td>
</tr>
<tr>
<td>2014</td>
<td>137</td>
<td>101</td>
<td>117</td>
<td>137</td>
<td>165</td>
</tr>
<tr>
<td>2015</td>
<td>141</td>
<td>89</td>
<td>74</td>
<td>93</td>
<td>129</td>
</tr>
<tr>
<td>2016</td>
<td>142</td>
<td>85</td>
<td>128</td>
<td>150</td>
<td>160</td>
</tr>
</tbody>
</table>

- The load reduction on extremely hot days has been in the range of 7% to 43%
2014 to 2016 Average RTP Load Profiles

RTP

- EXTREMELY HOT SUMMER WEEKDAY
- VERY HOT SUMMER WEEKDAY
- HOT SUMMER WEEKDAY
- MODERATE SUMMER WEEKDAY
- MILD SUMMER WEEKDAY
- HIGH COST WINTER WEEKDAY
- LOW COST WINTER WEEKDAY

MW vs. Hour (PST)
RTP Studies References


- George, S. et al., 2016. 2015 Load Impact Evaluation of Southern California Edison's Agriculture and Pumping Interruptible and Real-Time Pricing Programs
RTP vs Non-RTP

2015 RTP TOU-8-SUB

MW per Account

Hour (PST)

2015 TOU-8-SUB

MW per Account

Hour (PST)

2015 RTP TOU-8-PRI

KW per Account

Hour (PST)

2015 TOU-8-PRI

KW per Account

Hour (PST)
RTP Load Profiles by Industry

2016 RTP: Agriculture, Mining & Construction

2016 RTP: Manufacturing

2016 RTP: Wholesale, Transport, other Utilities
Appendix B

Real Time Pricing (RTP) at SCE White Paper
Real Time Pricing (RTP) at Southern California Edison (SCE)

Russell Garwacki, Lifan Pan, and Cyrus Sorooshian

Introduction

In California, there is increasing attention on the dynamic pricing structures of electricity that encourage customers to reduce load during peak hours. Load reductions decrease the market price of electricity and improve the overall efficiency of the grid. Critical peak pricing (CPP) has become the demand response program of choice in California as set by California Public Utilities Commission (CPUC) decision D.10-02-032 in 2009. In D.09-08-028 published in 2009, the Commission ordered SCE to propose a plan to default large customers with demands 200 kW and above onto CPP. In D.13-03-031 published in 2013, the Commission directed that SCE propose default CPP for commercial & industrial (C&I) customers with demands less than 200 kW and default CPP for large agricultural & pumping (AG&P) accounts. Real time pricing (RTP), however, is not getting a lot of attention compared to CPP. In this paper, we conduct a case study of the RTP experiences at SCE. We will provide a background for RTP at SCE, identify the rate penetration by industry, and provide the results of recent load impact evaluations. We will also provide a comparison to CPP and examine whether opt-in RTP is beneficial in lieu of default CPP for commercial and industrial customers. The experiences at SCE suggest that RTP is a better option compared to CPP because RTP rates send more accurate price signals; RTP load drop is significantly higher than CPP; RTP structure has the flexibility to offer low pricing during middle of the day to encourage consumption when over supply is possible.

Time-of-use (TOU) rate is a widely used dynamic pricing structure which adjusts the prices based on several time blocks. TOU prices are usually determined by season and hour, however it does not have a component to send price signals during the system peak hours. CPP rates usually include an add-on charge during critical peak hours on top of TOU rate. CPP rates send price signals during peak hours, which is an improvement on TOU. However, CPP still has two
main shortcomings. First, the price range is limited, and therefore the price volatility in the wholesale market is not well captured. Second, utilities can only call a limited number of critical peak hours\(^1\). RTP rates improve upon CPP via a pricing structure that typically changes hourly. RTP schedules are designed to reflect the hourly changes of the marginal cost or market prices sending price signals to customers to either shift load from higher-cost hours to lower-cost hours or forgo discretionary load during higher-cost hours. RTP could improve the performance of wholesale electricity markets by mitigating market power and dampen price volatility\(^2\).

Compared to CPP, RTP rates send more accurate pricing signals to customer. “While other mechanisms can be used to induce price-responsive demand and/or reduce peak demand, many economists argue that RTP represents the most direct and efficient demand response mechanism, and therefore it should be the focus of policymakers’ efforts to improve the performance of wholesale and retail electricity markets”\(^3\). According to a recent case study of the CPP program at Pacific Gas and Electric Company (PG&E), Blonz described the RTP program as the first-best policy and CPP as the second-best policy\(^4\). The study estimated that the CPP program recovers 43% RTP benefits assuming the same elasticity for both programs. Blonz also suggested that there would be substantial improvement for CPP program by increasing event price and reducing the number of events, because high pricing will generate more capacity construction savings and “lower number of event hours reduces the extra net consumer surplus loss that comes from non-super peak event day”. Comparing the CPP and RTP tariff at SCE (as shown in the next sections), RTP high-priced hours charge more per kWh than CPP event hours, while RTP has fewer high-priced hours than CPP event hours.

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Barbose et al. conducted a survey of RTP programs in the early 2000’s. At that time, there were more than 70 utilities in the U.S. that offered voluntary RTP rates. Most RTP programs had not been broadly marketed and thus had not achieved a significant level of participation. Most participants of the RTP programs were large industrial customers5.

SCE Real Time Pricing (RTP) Structure

Southern California Edison (SCE) has had a RTP program in place for more than 25 years. SCE initially launched a RTP pilot in 1987 with 10 accounts. In 1993, the number of RTP customers increased from 15 to 34. Currently SCE has about 150 industrial and commercial customers on this rate option. A brief timeline for the expansion of the RTP accounts across different rate groups in the recent years:

- Before 2009, only large accounts with demands higher than 500 kW (TOU-8) were enrolled in RTP.
- Agricultural and pumping accounts (TOU-PA-2 and TOU-PA-3) started to enroll in RTP from 2010.
- Commercial & Industrial (C&I) accounts with demands between 200 kW and 500 kW (TOU-GS-3) started to enroll in RTP from 2013.
- Smaller C&I accounts with demands less than 20 kW (GS-1) and 20 kW to 200 kW (GS-2) started to enroll in RTP from 2015.

TOU is currently the default rate for large accounts with demands larger than 500 kW (TOU-8) at SCE. SCE bills normally consist of a delivery portion and a generation portion. The rate structures of the delivery portion are similar for TOU-8 and RTP. The differences lie in the generation portion, which is illustrated in Table 1. The TOU-8 basic rate structure has both time differentiated energy charge and a time differentiated demand charge. In contrast, RTP recovers generation capacity costs from energy charges.

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Table 1  TOU vs. RTP Generation Rates

<table>
<thead>
<tr>
<th></th>
<th>TOU-8 (Standard Rate)</th>
<th>RTP Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Charge - $kWh/Meter/Month</td>
<td></td>
<td>Varied by Hour$^6$</td>
</tr>
<tr>
<td>Summer Season - On-Peak</td>
<td>0.07072</td>
<td></td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>0.04730</td>
<td></td>
</tr>
<tr>
<td>Off-Peak</td>
<td>0.03165</td>
<td></td>
</tr>
<tr>
<td>Winter Season - On-Peak</td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>0.04579</td>
<td></td>
</tr>
<tr>
<td>Off-Peak</td>
<td>0.03645</td>
<td></td>
</tr>
<tr>
<td>Demand Charge - $/kW of Billing Demand/Meter/Month</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>Time Related</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer Season - On-Peak</td>
<td>18.97</td>
<td></td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>3.58</td>
<td></td>
</tr>
<tr>
<td>Winter Season - On-Peak</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>0.00</td>
<td></td>
</tr>
</tbody>
</table>

There are currently nine different RTP pricing schedules for SCE customers. Pricing schedules are based on the day types and the prior day’s high temperature at the National Weather Service’s Downtown Los Angeles site. Table 2 illustrates the current generation portion of the TOU-8-SEC-RTP rate$^7$. The red color highlights the high-priced hours and green color highlights the low-priced hours. This heat map illustrates that high-priced hours occur in late afternoon and low-priced hours occur at night. The highest prices are around $2.5 per kWh in the 4 p.m. and 5 p.m. hour ending at Pacific Standard Time (PST) for extremely hot summer weekdays.

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$^6$ Detailed hourly rates shown in Table 2
$^7$ Testimony of Southern California Edison Company (U 338-E) in Support of its Application For Approval of its 2016 Rate Design Window Proposals
SCE has been using the same basic RTP structure for over 25 years but the industry has changed largely due to the increasing renewables portfolio standard (RPS). The influx of “zero-cost” renewable energy changes the cost curve. According to the California Independent System Operator (CAISO), the growth of renewable resources, mainly solar, changes the “traditional” electricity demand curve and causes oversupply in the middle of the day when solar is abundant. This has an adverse impact in balancing the supply and demand and maintaining the grid reliability. In SCE’s 2016 Rate Design Window Proposals A.16-09-003, SCE proposed to condense the current five summer-weekday price schedules into three day-types in order to

---

8 CAISO time-of-use periods analysis, 2016.
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M157/K905/157905349.PDF
simplify the rate structure and increase program enrollment\textsuperscript{9} as shown in Table 3. Summer weekdays will have three price schedules: days with highs below 80 degrees (mild summer weekdays); days with highs between 81 and 90 degrees (medium summer weekdays), and days with highs above 90 degrees (hot summer weekdays).

\textbf{Table 3  Proposed Generation \$ per kWh Rates}

\begin{tabular}{|c|c|c|c|c|c|c|c|c|}
\hline
HOUR ENDING@ PST & HOT SUMMER WEEKDAY ($\geq$91) & MEDIUM SUMMER WEEKDAY (81-90) & MILD SUMMER WEEKDAY ($\leq$80) & HIGH COST WINTER WEEKDAY ($\geq$90) & LOW COST WINTER WEEKDAY ($\leq$90) & HIGH COST WEEKEND ($\geq$78) & LOW COST WEEKEND ($\leq$78) \\
\hline
1 a.m. & 0.04208 & 0.04164 & 0.04112 & 0.04198 & 0.04123 & 0.04216 & 0.04098 \\
2 a.m. & 0.03999 & 0.03919 & 0.03913 & 0.04072 & 0.04015 & 0.04103 & 0.03999 \\
3 a.m. & 0.03932 & 0.03877 & 0.03885 & 0.03984 & 0.03992 & 0.04068 & 0.03976 \\
4 a.m. & 0.03899 & 0.03873 & 0.03890 & 0.03989 & 0.03986 & 0.04056 & 0.03970 \\
5 a.m. & 0.03941 & 0.03890 & 0.03941 & 0.04057 & 0.04024 & 0.04069 & 0.03979 \\
6 a.m. & 0.04105 & 0.04046 & 0.04059 & 0.04230 & 0.04194 & 0.04105 & 0.04036 \\
7 a.m. & 0.04407 & 0.04259 & 0.04036 & 0.04855 & 0.04664 & 0.04184 & 0.04023 \\
8 a.m. & 0.03966 & 0.03877 & 0.03719 & 0.04315 & 0.04614 & 0.03899 & 0.03830 \\
9 a.m. & 0.03668 & 0.03655 & 0.03397 & 0.03847 & 0.03859 & 0.03235 & 0.02801 \\
10 a.m. & 0.03618 & 0.03568 & 0.03391 & 0.03572 & 0.03605 & 0.02947 & 0.02291 \\
11 a.m. & 0.03596 & 0.03572 & 0.03552 & 0.03540 & 0.03489 & 0.03070 & 0.02235 \\
12 noon & 0.03678 & 0.03670 & 0.03440 & 0.03512 & 0.03405 & 0.03194 & 0.02143 \\
1 p.m. & 0.03753 & 0.03770 & 0.03469 & 0.03477 & 0.03275 & 0.03186 & 0.02021 \\
2 p.m. & 0.03891 & 0.03978 & 0.03618 & 0.03563 & 0.03376 & 0.03323 & 0.02099 \\
3 p.m. & 0.04202 & 0.04244 & 0.03769 & 0.03887 & 0.03599 & 0.03506 & 0.02445 \\
4 p.m. & 0.04605 & 0.04558 & 0.03919 & 0.03970 & 0.03752 & 0.03829 & 0.03013 \\
5 p.m. & 0.06097 & 0.05094 & 0.04120 & 0.04752 & 0.05328 & 0.05146 & 0.04736 \\
6 p.m. & 0.29593 & 0.07631 & 0.06518 & 0.19036 & 0.11059 & 0.12770 & 0.07011 \\
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8 p.m. & 2.77435 & 0.13441 & 0.08792 & 0.06521 & 0.06733 & 0.08667 & 0.06384 \\
9 p.m. & 0.57124 & 0.07432 & 0.06425 & 0.05917 & 0.05786 & 0.05884 & 0.05442 \\
10 p.m. & 0.13366 & 0.05994 & 0.05935 & 0.05232 & 0.05195 & 0.05359 & 0.05143 \\
11 p.m. & 0.05270 & 0.05005 & 0.04946 & 0.04907 & 0.04732 & 0.04945 & 0.04781 \\
Midnight & 0.04481 & 0.04430 & 0.04299 & 0.04352 & 0.04276 & 0.04369 & 0.04264 \\
\hline
\textbf{# of Days} & 11 & 39 & 36 & 7 & 168 & 47 & 57 \\
\hline
\end{tabular}

\textsuperscript{9} Testimony of Southern California Edison Company (U 338-E) in Support of its Application For Approval of its 2016 Rate Design Window Proposals
SCE’s proposed new RTP rates reflect the new generation cost curve as it takes into account the increasing penetration of renewable resources. Comparing the proposed rates (Table 3) to the current rates (Table 2), the highest prices will occur in the early evening instead of late afternoon and the lowest prices will occur in the middle of the day when solar output is at or near its peak and system demands are below theirs.

The prior day’s Downtown Los Angeles high temperature is chosen to define the day types since it is highly correlated with the system load. The purpose of RTP, like any demand response program is to reduce peak demand. Therefore, the trigger has to be highly correlated with the system load. The following figure shows that the correlation between prior day’s Downtown Los Angeles maximum temperature and SCE’s daily system peak is 0.79 on summer workdays. Meanwhile, the correlation between same day’s Downtown Los Angeles maximum temperature and SCE’s daily system peak is 0.87 on summer workdays.

Figure 1 Correlation between Temperature and SCE daily system peak (Summer Workdays: 2008 – 2015)
The following table shows the correlation among the prior day’s temperature, same day’s temperature and SCE daily system peak for various day types. In general, the performance of the prior day's temperature is close to the same day's temperature which makes it good temperature proxy.

<table>
<thead>
<tr>
<th>Day Type</th>
<th>Prior Day's Downtown Los Angeles Site Maximum Temperature</th>
<th>Same Day's Downtown Los Angeles Site Maximum Temperature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Workdays</td>
<td>0.79</td>
<td>0.87</td>
</tr>
<tr>
<td>All Days</td>
<td>0.74</td>
<td>0.80</td>
</tr>
<tr>
<td>Annual</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Workdays</td>
<td>0.67</td>
<td>0.70</td>
</tr>
<tr>
<td>All Days</td>
<td>0.63</td>
<td>0.66</td>
</tr>
</tbody>
</table>

Table 4

Table 5 shows the number of days for different RTP day types from 2008 to 2016. The number of extremely hot days (>=95 degrees) were in the range of 0 to 6 days; the number of very hot days (91-94 degrees) were in the range of 1 to 8 days. 2015 had the most hot summer workdays. The proposed hot summer workdays (>=91 degrees) stabilize the number of high priced days, as it is less variable than the current extremely hot summer weekdays (>=95 degrees).

Table 5 SCE's Real-Time Pricing Day Types (2008-2016)
SCE RTP Load Impact

SCE conducted an early study regarding the RTP load impact in 1993 and the load reduction was around 30% when comparing hot summer weekdays to mild summer weekdays at the highest-cost hours, from 2 p.m. to 4 p.m. PST hour ending. In recent years, the SCE system peaks later in the day; and to reflect that, the RTP rates assign the highest prices to the hours ending at 4 p.m. and 5 p.m. PST. In this paper, we compare the average load profiles for the extremely hot summer weekdays (>= 95 degrees) and the mild summer weekdays (<=80 degrees) pricing schedules since those two schedules were the highest and lowest priced RTP schedules in summer. We then measure the RTP load drop using the following formula:

\[
\text{Average load drop} = \text{average load (hot summer weekdays)} - \text{average load (mild summer weekdays)} \text{ for the highest priced hours, 4 p.m. and 5 p.m. (PST hour ending).}
\]

The results are presented in Table 6. The number of RTP accounts at SCE gradually increased over the years. Load impact increased from 10% to 25% in 2010 since the enrollment of another large account in 2010, which consistently curtailed a large amount of load during high-priced hours. The percentage of load reduction is in the range of 25% to 54% on extremely hot summer weekdays and in the range of 19% to 40% on very hot summer weekdays since 2010.


11 The overall load reduction for RTP customers is heavily impacted by one very large customer, which accounts up to 50% of SCE’s entire RTP load. In order to remove the variation due to this single large account, we measure the RTP load impact by excluding this account. The load impact table for all RTP accounts can also be found in the appendix Table 10.
Besides the load reduction on extremely hot summer weekdays, there has been consistent reductions on very hot days, which indicates customers’ willingness and ability to reduce load on very hot days as well and is reason to consolidate these two day types.

Table 6 RTP Load Impact – Excluding One Large Account

<table>
<thead>
<tr>
<th>Year</th>
<th>Average Number of Accounts</th>
<th>Average Number of TOU-8 Accounts (Demand Larger than 500 KW)</th>
<th>Avg Load (MW) for Hour 4 p.m. and 5 p.m. (PST Hour Ending)</th>
<th>Extremely Hot Summer Weekday Load Impact</th>
<th>Very Hot Summer Weekday Load Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>EXTREMELY HOT SUMMER WEEKDAY (&gt;=95)</td>
<td>VERY HOT SUMMER WEEKDAY (91-94)</td>
<td>MILD SUMMER WEEKDAY (&lt;=80)</td>
</tr>
<tr>
<td>2008</td>
<td>77</td>
<td>77</td>
<td>54</td>
<td>59</td>
<td>58</td>
</tr>
<tr>
<td>2009</td>
<td>83</td>
<td>83</td>
<td>43</td>
<td>40</td>
<td>48</td>
</tr>
<tr>
<td>2010</td>
<td>92</td>
<td>87</td>
<td>40</td>
<td>43</td>
<td>53</td>
</tr>
<tr>
<td>2011</td>
<td>128</td>
<td>97</td>
<td>44</td>
<td>40</td>
<td>63</td>
</tr>
<tr>
<td>2012</td>
<td>125</td>
<td>96</td>
<td>NA</td>
<td>50</td>
<td>69</td>
</tr>
<tr>
<td>2013</td>
<td>123</td>
<td>94</td>
<td>41</td>
<td>55</td>
<td>89</td>
</tr>
<tr>
<td>2014</td>
<td>136</td>
<td>100</td>
<td>54</td>
<td>64</td>
<td>97</td>
</tr>
<tr>
<td>2015</td>
<td>140</td>
<td>88</td>
<td>41</td>
<td>52</td>
<td>86</td>
</tr>
<tr>
<td>2016</td>
<td>141</td>
<td>84</td>
<td>42</td>
<td>55</td>
<td>73</td>
</tr>
</tbody>
</table>

Figure 2 shows the average RTP load profiles for various weekday RTP day types from 2014 to 2016. Figure 3 shows the daily pattern of the generation portion of the RTP rates (same information as Table 2). Looking at Figure 2 and Figure 3 together, it can be seen that there was a clear load drop on extremely hot, very hot and hot summer workdays in high-priced afternoon hours compared to the mild summer days.
Figure 2: Average of 2014 - 2016 RTP Load Profiles - Excluding Largest Account

RTP Load Profiles

- EXTREMELY HOT SUMMER WEEKDAY
- VERY HOT SUMMER WEEKDAY
- HOT SUMMER WEEKDAY
- MODERATE SUMMER WEEKDAY
- MILD SUMMER WEEKDAY
- LOW COST WINTER WEEKDAY
- HIGH COST WINTER WEEKDAY

Figure 3 Generation $ per kWh Rates

Current TOU-8-SEC-RTP Generation Prices

- EXTREMELY HOT SUMMER WEEKDAY
- VERY HOT SUMMER WEEKDAY
- HOT SUMMER WEEKDAY
- MODERATE SUMMER WEEKDAY
- MILD SUMMER WEEKDAY
- LOW COST WINTER WEEKDAY
- HIGH COST WINTER WEEKDAY
Figure 4 2015 Load Profile of RTP accounts

2015 RTP TOU-8-SEC

Kw per Account

1  2  3  4  5  6  7  8  9  10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour (PST)

- EXTREMELY HOT SUMMER WEEKDAY
- VERY HOT SUMMER WEEKDAY
- MILD SUMMER WEEKDAY

Figure 5 2015 Load Profile of Non-RTP accounts

2015 TOU-8-SEC

Kw per Account

1  2  3  4  5  6  7  8  9  10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour (PST)

- EXTREMELY HOT SUMMER WEEKDAY
- VERY HOT SUMMER WEEKDAY
- MILD SUMMER WEEKDAY
RTP load profiles are very different from non-RTP load profiles (see Figure 4 for RTP load profiles and Figure 5 for non-RTP profiles). In general, average RTP profiles show a peak in the morning and a dip in the afternoon. Non-RTP loads are flatter. Meanwhile, the non-RTP profiles appear to be temperature sensitive and energy consumption is higher on hot days than on mild days, which provides an opportunity for load reduction once the non-RTPs switch to RTP. There are two possible explanations for the differences in RTP vs. non-RTP load profiles. First, the RTP load profile started out differently in the first place before they went on RTP. Second, RTP customers change their electricity usage pattern as they adapt to the RTP rate structure.

SCE has contracted with Nexant Inc. for the RTP load impact study in recent years. Nexant used a regression model with variables such as hourly price, calendar, and temperature to model the hourly load. Nexant’s report measured the average load drop for longer hours from 1p.m. to 6 p.m. instead of the two-hour window in this study. The 2015 study estimated that there was a 32.8% reduction on the system peak day, which was an extremely hot summer workday. SCE’s method (comparing load profiles) shows a high load drop in 2015 as well.

**Market Penetration and Bill Impacts**

Table 7 shows the 2016 RTP load impact by industry. Three activity sectors that show significant load drop during high-priced hours are: Agriculture, Mining & Construction; Manufacturing; Wholesale, Transport, and other Utilities. Other industry sectors including retail stores; offices, hotels, health services; schools; government, entertainment, and other services either show no load drop or have too few accounts to draw the conclusion. In general, the RTP load impacts are more significant in non-customer facing sectors. Customer-facing sectors may have less flexibility or desire to change electricity consumption in respond to the hourly prices.

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12 George, S. et al., 2016. 2015 Load Impact Evaluation of Southern California Edison’s Agriculture and Pumping Interruptible and Real-Time Pricing Programs
Table 7 2016 SCE’s RTP Load Impact by Industry

<table>
<thead>
<tr>
<th>Industry Group</th>
<th>2-digit SIC</th>
<th>Average Number of RTP Accounts</th>
<th>Avg Load (MW) for Hour 4 p.m. and 5 p.m. (PST Hour Ending)</th>
<th>Extremely Hot Summer Weekday Load Impact</th>
<th>Very Hot Summer Weekday Load Impact</th>
<th>% of TOU-8 (&gt; 500 kW) on RTP in term of Annual Usage</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Agriculture, Mining &amp; Construction</td>
<td>19 and below</td>
<td>26</td>
<td>7</td>
<td>8</td>
<td>9</td>
<td>-2 -21% -1 -11% 6%</td>
</tr>
<tr>
<td>2. Manufacturing</td>
<td>20-39</td>
<td>53</td>
<td>114</td>
<td>136</td>
<td>142</td>
<td>-27 -19% -6 -4% 9%</td>
</tr>
<tr>
<td>3. Wholesale, Transport, other Utilities</td>
<td>40-51</td>
<td>28</td>
<td>4</td>
<td>4</td>
<td>7</td>
<td>-3 -41% -4 -48% 2%</td>
</tr>
<tr>
<td>4. Retail Stores; Offices, Hotels, Health, Services; Schools; Gov’t, Entertainment, Other Services</td>
<td>52 and above</td>
<td>35</td>
<td>2</td>
<td>3</td>
<td>2</td>
<td>0 0% 0 16% 0%</td>
</tr>
</tbody>
</table>

The penetration of RTP in the three industries is 6%, 9%, and 2% among the large C&I (>500 kW) accounts. For large accounts with demand higher than 500 kW, RTP rates save them around 15% compared to the standard TOU-8 rates (Table 8). The bill impact results are based on the current RTP and TOU-8 rates. While current RTP participation is low at SCE and RTP rates provide sizable bill savings, there would appear to be potential to further market the RTP program to large C&I accounts.

Table 8 Bill Impacts: RTP vs Standard TOU-8 rate

<table>
<thead>
<tr>
<th>TOU-8 (Demand higher than 500 kW)</th>
<th>Bill Savings on RTP vs. Standard TOU-8 Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>TOU-8-SUB RTP (Voltages above 50 KV)</td>
<td>-13%</td>
</tr>
<tr>
<td>TOU-8-PRI RTP (Voltages from 2 KV to 50 KV)</td>
<td>-22%</td>
</tr>
<tr>
<td>TOU-8-SEC RTP (Voltages Below 2 KV)</td>
<td>-19%</td>
</tr>
<tr>
<td>All TOU-8 RTP</td>
<td>-15%</td>
</tr>
</tbody>
</table>
SCE Critical Peak Pricing (CPP) Structure

SCE started its optional CPP program in 2003 and eligible customers could enroll in optional CPP rates by October 2009. SCE started to default large accounts with demand higher than 200 kW onto CPP in October 2009 in compliance with D.09-08-028. Around 7,000 accounts were defaulted onto CPP and customers could opt out of CPP at any time. A recent customer count shows that around 24% of the defaulted accounts remain on CPP.

SCE calls 12 CPP events per year. SCE's CPP rate structure incorporates a CPP adder on top of the TOU rate. During a CPP event, the event surcharge is around $1.3/ kWh. In return, customers get bills credits during the summer months. CPP events can be called based on California Independent System Operator (CASIO) system demand or alert, forecasts of SCE system emergencies, forecasts of extreme temperature conditions, and day-head load/price forecast. The critical peak hours are currently from 2 p.m. to 6 p.m. on non-holiday weekdays. In the 2016 Rate Design Window application, SCE proposed to revise the TOU on peak period and CPP period to 4 p.m. to 9 p.m. on non-holiday weekdays in response to the changing electricity cost curves. The increase in energy from renewable generation sources causes a steep ramp in demand during the hours when power generated by renewable resources tapers off while customer demand still remains high. The alignment of TOU and CPP periods will help to mitigate the situation.

SCE Critical Peak Pricing (CPP) Load Impact

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13 Testimony of Southern California Edison Company (U 338-E) in Support of its Application For Approval of its 2016 Rate Design Window Proposals
SCE has contracted with several consulting companies (Nexant; Freeman, Sullivan &co.; Christensen Associates Energy Consulting, LLC) to measure the CPP load impact. Table 8 shows the measurement of the CPP impact for the current participants with demand higher than 200 kW from 2008 to 2015\textsuperscript{14}. CPP impacts have been examined using regression models with variables such as load, calendar, temperature, etc. Table 9 shows that double-digits load impact for opt-in CPP accounts at 26% and 19% in 2008 and 2009. Respectively, load reduction for SCE has been stable at around 5% from 2010 to 2015 with several thousand participants who were mostly defaulted CPP accounts.

For CPP, there is a large variation of load impact for opt-in and default programs. For example, the load drop was 25 MW for 476 opt-in CPP accounts in 2009. Meanwhile, the load drop was 29 MW for 2,677 CPP accounts (mostly defaulted) in 2015. There was only a slight increase of 4 MW load impact from 2009 to 2015, but with more than 5 times the number of participants.

\texttt{http://www.calmac.org/publications/PY08_CPP_ExtAnte_report_CAEC_20090501ES.pdf}
\texttt{http://www.calmac.org/publications/PY09_CPP_Ex_Post_Ex_Ante_final_report_CAEC_20100419.pdf}
\texttt{http://www.calmac.org/publications/PY09_AutoDR_Cost_Effectiveness_20100927_FinalES.pdf}
George, S. et al., 2011. 2010 California Statewide Non-Residential Critical Peak Pricing Evaluation 
\texttt{http://www.calmac.org/publications/2010_California_Non_Residential_CPP_Evaluation_-_FINAL.pdf}
\texttt{http://www.calmac.org/publications/CPP_Statewide Program Year 2011 Load Impact Study.pdf}
\texttt{http://www.calmac.org/publications/2012_Non-Res_CPP_Statewide_Evaluation_-_FINAL.pdf}
George, S. et al., 2015. 2014 Load Impact Evaluation of California’s Statewide Non-residential Critical Peak Pricing Program 
George, S. et al., 2016. 2015 Load Impact Evaluation of California’s Statewide Nonresidential Critical Peak Pricing Program 
\texttt{http://www.calmac.org/%5C%5C/publications/7__Statewide_2015_CPP_Report.pdf}
SCE is currently ordered to default all small C&I customers with less than 200 kW onto CPP. CPP load impacts are much lower for small C&I customers than larger C&I customers. In the 2016 SCE's rate design window application, SCE used the load impact results from PG&E’s study and illustrated that 67,000 C&I 20-200 kW accounts will have an aggregate load impact of 3.2 MW and 450,000 C&I less than 20 kW accounts will have an aggregate load impact of 1.3 MW. SCE’s total estimated 2015 DR portfolio is 1,457 MW, e.g., 691-MW base interruptible program (BIP), 369-MW Summer Discount Plan (SDP), and 115-MW demand bidding program (DBP). Defaulting 45,000 C&I less than 20 kW accounts is expected to increase SCE’s demand response portfolio by merely 0.09%.

Table 9 CPP Load impact

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of CPP Accounts</th>
<th>Estimated Reference Load (MW)</th>
<th>Observed Load (MW)</th>
<th>Estimated Load Impact (MW)</th>
<th>Load Impact (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>201</td>
<td>60</td>
<td>45</td>
<td>-15</td>
<td>-26.0%</td>
</tr>
<tr>
<td>2009</td>
<td>476</td>
<td>130</td>
<td>106</td>
<td>-25</td>
<td>-18.9%</td>
</tr>
<tr>
<td>2010</td>
<td>4,100</td>
<td>1077</td>
<td>1047</td>
<td>-31</td>
<td>-2.8%</td>
</tr>
<tr>
<td>2011</td>
<td>3,000</td>
<td>615</td>
<td>580</td>
<td>-35</td>
<td>-5.7%</td>
</tr>
<tr>
<td>2012</td>
<td>2,508</td>
<td>554</td>
<td>521</td>
<td>-33</td>
<td>-5.0%</td>
</tr>
<tr>
<td>2013</td>
<td>2,495</td>
<td>613</td>
<td>577</td>
<td>-36</td>
<td>-5.8%</td>
</tr>
<tr>
<td>2014</td>
<td>2,670</td>
<td>594</td>
<td>565</td>
<td>-30</td>
<td>-5.0%</td>
</tr>
<tr>
<td>2015</td>
<td>2,667</td>
<td>582</td>
<td>553</td>
<td>-29</td>
<td>-5.0%</td>
</tr>
</tbody>
</table>

Table 10

SCE Estimated CPP Load Impact by Customer Size

<table>
<thead>
<tr>
<th>Customer Group</th>
<th>PG&amp;E Load Impacts per Account</th>
<th>SCE Approx. Accounts Impacted by Default CPP</th>
<th>Estimated Enrollment Rate After Customer Opt-Outs</th>
<th>SCE Illustrative Aggregate Load Impacts</th>
<th>CPP MW as % of SCE’s Total CPP Load Impacts</th>
<th>CPP MW as % of SCE’s Total DR Portfolio</th>
</tr>
</thead>
<tbody>
<tr>
<td>C&amp;I 20-200 kW</td>
<td>0.200 kW</td>
<td>67,000</td>
<td>24%</td>
<td>3.2 MW</td>
<td>11.9%</td>
<td>0.22%</td>
</tr>
<tr>
<td>C&amp;I less than 20 kW</td>
<td>0.012 kW</td>
<td>450,000</td>
<td>24%</td>
<td>1.3 MW</td>
<td>4.5%</td>
<td>0.09%</td>
</tr>
</tbody>
</table>

15 SCE’s August 2015 DRP and ILP Report
16 Testimony of Southern California Edison Company (U 338-E) in Support of its Application For Approval of its 2016 Rate Design Window Proposals
SCE believes that defaulting the 450,000 service accounts would reduce customer satisfaction and cause major administrative burden to process the default and later customers' opt-out of the CPP tariff in exchange for limited demand response value\textsuperscript{17}. The costs far outweigh the benefits.

**Conclusion**

Compared to CPP rates, RTP program looks promising in terms of the level of load reduction. For example, RTP had a 45 MW load drop on extremely hot summer weekdays and 34 MW load drop on very hot summer weekdays for 140 participating accounts in 2015 (Table 6). Meanwhile, the load drop for CPP accounts with demand higher than 200 kW was 29 MW for 2,677 accounts in 2015 (Table 9). As table 10 shows, it is estimated that there will be minimal (1.3 MW) load impact once 450,000 C&I accounts with demands less than 20 kW will be defaulted onto CPP. RTP program had a higher load drop than CPP with fraction of the participants. SCE would get far more load drop from a handful of large RTP accounts than all of small customers that will be defaulted onto CPP. In terms of program effectiveness, there would appear to be more potential to market the opt-in RTP in lieu of default CPP.

Further, SCE's current RTP structure is flexible enough so that it can be modified to promote more consumption during the matinee period. The Commission ordered the utilities to offer more attractive pricing during the matinee Period (from 10 a.m. to 4 p.m.) “that would encourage a shift in energy use by commercial, industrial, and agricultural users to alternative times of the day when abundant renewable and low-water-using energy are produced at high (and growing) quantities”\textsuperscript{18}. SCE’s modified RTP rate structures do exactly that.

**Appendix**

\textsuperscript{17} Testimony of Southern California Edison Company (U 338-E) in Support of its Application For Approval of its 2016 Rate Design Window Proposals

\textsuperscript{18} Matinee Pricing ACR at 2-3
Table 11 shows that the percentage of load reduction was in the range of 25% to 54% on extremely hot summer weekday and in the range of 19% to 40% on very hot summer weekday since 2010.

<table>
<thead>
<tr>
<th>Year</th>
<th>Average Number of Accounts</th>
<th>Average Number of TOU-8 Accounts (Demand Larger than 500 kW)</th>
<th>Avg Load (MW) for Hour 4 p.m. and 5 p.m. (PST Hour Ending)</th>
<th>Extremely Hot Summer Weekday Load Impact</th>
<th>Very Hot Summer Weekday Load Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>EXTREMELY HOT SUMMER WEEKDAY (&gt;=95)</td>
<td>MW</td>
<td>%</td>
</tr>
<tr>
<td>2008</td>
<td>78</td>
<td>78</td>
<td>113</td>
<td>-21</td>
<td>-16%</td>
</tr>
<tr>
<td>2009</td>
<td>84</td>
<td>84</td>
<td>116</td>
<td>-9</td>
<td>-7%</td>
</tr>
<tr>
<td>2010</td>
<td>93</td>
<td>88</td>
<td>107</td>
<td>-26</td>
<td>-20%</td>
</tr>
<tr>
<td>2011</td>
<td>129</td>
<td>98</td>
<td>107</td>
<td>-26</td>
<td>-20%</td>
</tr>
<tr>
<td>2012</td>
<td>126</td>
<td>97</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>2013</td>
<td>124</td>
<td>95</td>
<td>110</td>
<td>-47</td>
<td>-30%</td>
</tr>
<tr>
<td>2014</td>
<td>137</td>
<td>101</td>
<td>117</td>
<td>-47</td>
<td>-29%</td>
</tr>
<tr>
<td>2015</td>
<td>141</td>
<td>89</td>
<td>74</td>
<td>-55</td>
<td>-43%</td>
</tr>
<tr>
<td>2016</td>
<td>142</td>
<td>85</td>
<td>128</td>
<td>-32</td>
<td>-20%</td>
</tr>
</tbody>
</table>

Figure 5 Average of 2014 - 2016 RTP Load Profiles
Figure 6 shows the average RTP load profiles for various weekday day types from 2014 to 2016 for all RTP accounts.

Figure 7 shows the RTP load profile by industry. ‘Manufacturing’, ‘Wholesale, Transport, other Utilities’ show significant amount of load drop. ‘Agriculture, Mining & Construction’ shows smaller yet noticeable load drop.
Appendix C
Using Loss of Load Expectation (LOLE) to Allocate Generation
Capacity to Peak and Flexibility Need
Using Loss of Load Expectation to Allocate Generation Capacity to Peak and Flexibility Need

Paul Nelson, Benjamin Baker*

June 30, 2017
Rugters Advanced Workshop in Regulation and Competition
Monterey, CA

*The views expressed in this presentation are the authors and do not necessarily reflect the views of Southern California Edison
Executive Summary

• A loss of load expectation (LOLE) model can determine the likely hours when customer outages occur due to a lack of peak and/or ramping capacity
  • Price signals can be sent to customers to change demand to avoid outage due to lack of capacity

• Tested two LOLE models
  • Evaluated 1 day in 10 years LOLE for a single capacity constraint
  • An exploratory combined LOLE model that simultaneously evaluates for multiple capacity constraints
    • Model needs further refinement before use in a ratemaking proceeding

• Rate design is one tool to manage ramping by sending price signals to change customer demand
  • Other tools include curtailment or new resources

• Purpose of study to show proof of concept
  • Inputs and results were NOT verified for accuracy necessary for ratemaking
Shrinking demand and increasing renewables is leading to new grid operation concerns

- Historically peak has been the primarily reliability issue in the CAISO
  - Ramp is an emerging reliability issue due to the increasing renewable penetration
  - Ramp need is defined as the change in net load over a 3 hours period

- Customer rates have been used to help manage load during period of daily peaks
  - Could be used to help manage load during periods of ramp
    - Increase demand the “belly” or lower demand during the “head” of the duck curve

- Need to identify when a potential reliability concern could occur due to peak or ramp in order to send proper price signals to mitigate capacity constraints
  - LOLE can be used to identify those periods
Allocating Generation Capacity Marginal Cost

• Due to changing nature of grid, capacity additions for reliability must be able to serve the operational constraints on the grid such as peak and/or ramp

• Price signals could be sent to customers when capacity is most needed
  • Price should reflect the cost of a marginal capacity resource such as a combustion turbine (CT) which can meet peek and ramp needs

• A resources capacity values are defined as:
  • Peak: net qualifying capacity (NQC) of a resources in resource adequacy (RA)
  • Ramp: effective flexible capacity (EFC) is a resources ability to dispatch over a three hour window (per CAISO tariff)
    • This definition may change as product becomes more defined
    • Not all resources qualified to serve peak can serve ramp
Loss of Load Expectation (LOLE)

- Performs evaluation to determine what hours in year are more likely to experience a 1 day in 10 year outage event (1 in 10 LOLE) relative to the other hours in year
  - 1 day in 10 year outage could be a single hour with 100% probability of experiencing an outage or the sum of probable outage hours over a year
- Takes into account different load patterns and unit availability outcomes
  - Performed for every hour of the year
- A stochastic model is used to compare capacity needs vs available capacity for many load, wind, and solar outcomes to develop a likelihood of hourly outage
Proof of Concept LOLE Methodologies

- **Primary Methodology:** Solving for 1 in 10 LOLE caused by peak and ramp separately
  - Requires modeler to use an exogenous variable to combine 1 in 10 LOLE hours for peak and ramp

- **Exploratory Methodology**
  - New concept of solving for 1 in 10 LOLE caused by ramp and peak simultaneously
  - Removes need for exogenous variable
  - Still in the process of being studied and improved upon

- Studies ran at CAISO level for the years 2018-2026

Randomly sample ~5% of all daily combinations (wind and solar randomly selected in month)

Example draw for a day:
All data scaled to energy in study year
30 January 1st Days -
30 January Solar Days -
30 January Wind Days

Sample ~5% of all load, wind, and solar combinations to create net load and net load ramp daily curves

Evaluate sample for LOLE by hour for whole year

• Probability that available resources minus outages cannot serve need

Scale needs up or down until a 1 day in 10 yr LOLE is achieved

• Repeat previous steps after scaling the peak and ramp needs

Combine 1 in 10 LOLE results for both ramp and peak

• Utilizes an independent weighting factor that simulates the changing grid constraints between peak and ramp
• LOLE is weighted towards peak but ramp is a limiting constraint in some hours

• Split between peak and ramp derived from the ratio between the largest average net load peak and net load ramp

• Would need to consider how to spread the price signal to customers during ramp

Southern California Edison
Analytical framework of a Combined LOLE Methodology

- Exploratory methodology to solve for a 1 in 10 LOLE caused by peak and/or ramp simultaneously

- Similar to previous LOLE methodology except tool evaluates for both peak and ramp simultaneously
  - Removes need for exogenous multiplier

- When shifting needs to find 1 in 10 both needs must be shifted by same multiplier to ensure the relative ratio between the needs is maintained
LOLE Combined LOLE Proof of Concept Results

- LOLE value weighted all towards peak or ramp
- The ratio between peak capacity and peak is increasing while the ratio between ramp capacity and ramp is decreasing
- Though peak LOLE is decreasing relative to ramp LOLE the peak hours should still be considered a limiting constraint on the system
  - Further concept development before use in ratemaking
  - Other ways of managing ramp without of additional capacity
Conclusion

• LOLE results can be used to allocate capacity costs to hours in a year
  • These hours can inform rate making to send price signals to influence customer demand so that additional capacity can be avoided or costs can be recovered from the appropriate customer

• Ramping may also be managed by other solutions such as renewable generation curtailment
  • Customer demand should not be priced higher than the value/opportunity cost of renewable curtailment

• Purpose of study was to show proof of concept
  • Inputs and results were NOT verified for accuracy necessary for ratemaking
Appendix D
Using Loss of Load Expectation (LOLE) to Allocate Generation
Capacity to Peak and Flexibility Need White Paper
Using Loss of Load Expectation (LOLE) to Allocate Generation Capacity to Peak and Flexibility Need

By Paul D Nelson and Ben Baker

The allocation of generation capacity to time periods using a distribution of loss of load expectation (LOLE) has historically been focused on the necessity to meet peak capacity. This paradigm is changing with the increase of renewables such as wind and solar, which are changing the operation of California’s grid. One of the largest changes is the potential for operational constraints due to increasing ramps that capacity must be able to serve. The need for capacity to serve these new ramp constraints could be limited if price signals are sent to consumers at the appropriate hours in the year. This paper examines the use of LOLE to allocate generation capacity between peak and ramping needs for rate making purposes.

1 The opinions and conclusions are those of the authors and not Southern California Edison. The authors would like to thank Eric Wang, Alex Vandenbroek, and Louis Linden for their contribution and feedback during the drafting process.
Description of the problem

As load serving entities (LSE) move towards meeting California’s goal to obtain 50% of energy sales from renewable resources by 2030, the dynamics of grid operations are changing. This is due to increased levels of intermittent renewable generation that is not subject to dispatch control by the system operator.\(^2\) This creates new challenges in maintaining system reliability. One of these challenges is having sufficient ramp capability from dispatchable generation at times when solar output is rapidly decreasing and evening load is increasing. Figure 1 shows how renewable generation decline in the afternoon combined with the increasing load for the evening peak which creates a net load\(^3\) that has a steeper increase in the 16:00-20:00 hour period. It is this net load that must be served by generation that is subject to dispatch control.

Figure 1: Example of Load and Renewable generation during spring months

The CAISO has called net load the “duck curve” and is shown in Figure 2 and illustrates the growing need for ramp over a three hour period during a spring day through 2020.\(^4\). As more solar generation is constructed to meet California’s renewable policy goals, the duck curve will become even

\(^2\) Typically, wind and solar generate whatever amount is feasible based upon current conditions and are not dispatched at specific output levels.

\(^3\) Net load is defined as load minus wind minus solar production.


more dramatic. If customer demand increases during the evening hours, then the “head” (6pm-9pm) of the duck moves higher which would increase the ramping requirements from the “belly” (2-3pm).

Figure 2: The Duck Curve

Resources can be procured to meet these new challenges; however, the problem can also be partially managed by sending price signals to change the pattern of discretionary energy demand.5 If prices are reduced during the period of the belly of the duck, which should increase demand, then the belly can be made slimmer. Also, the head could be made lower by reducing demand with an increase in price. The combination of these two would reduce ramping needs and may lower the likelihood of an outage depending on the responsiveness of customers to price signals. This idea of sending price signals to customers during times of high ramp was introduced by Southern California Edison (SCE) in their 2016 Rate Design Window (RDW) application.6 The price signal should reflect the marginal cost of procuring additional resource capacity.7 The outcome of this signal should result in the right economic decision

5 The customer’s price elasticity will be a limiting factor, which for certain uses and times of the day can be rather inelastic.
7 The marginal capacity resources has been the combustion turbine as it is the cheaper resource to serve a marginal increase in demand.
between a customer’s value of demand and the load serving entity’s (LSE) cost of proving additional resources.

SCE proposed that capacity could be split between peak and ramp on the basis that the marginal capacity resource is a combustion turbine (CT) since it could serve both needs of peak and ramp. This study will present a proof of concept method that can help determine the primary driver between peak and ramp of additional resource need.

The authors do not intend to determine or make the claim that there is a capacity need for peak or ramp in the future. Instead, the goal is to demonstrate a method that allocates capacity values across a year by evaluating simulated loss of load caused by peak and ramp capacity shortfall. These identified times could be used to send price signals to customers which reflect the marginal cost of additional capacity. If customers respond to the price signals by shifting their usage to another time period, it may ease future grid operation challenges.

Definition of flexible need and capacity

As previously discussed, the need for flexible capacity is of increasing concern regarding grid reliability to meet rapid changes in load over time, also known as ramp or ramping. The CAISO presently defines the need for ramp as the change in net load over a three hour period for resource adequacy (RA) purposes and is subsequently used in this study. This definition was also used by SCE in its 2016 RDW, however a deterministic approach of applying ramp to rate making was used instead of a stochastic LOLE approach.

The CAISO evaluates two different periods for ramp. The “primary net load ramp” which occurs during the afternoon when solar production is declining but load is already high or increasing and “secondary net load ramp” which occurs during the morning when load is increasing and wind

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http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/330EE0C2DAEDB1828825802200055AD8/$FILE/A1609xxx-SCE-Various-SCE-01%20Testimony%20In%20Support%20of%202016%20RDW%20Application.pdf

9 Net load is defined as load minus wind minus solar production.

10 More details are provided in the section on definition of flexible need.

http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/330EE0C2DAEDB1828825802200055AD8/$FILE/A1609xxx-SCE-Various-SCE-01%20Testimony%20In%20Support%20of%202016%20RDW%20Application.pdf
production is falling off. For simplicity, this study assumed the secondary net load ramp is considered to be any upward net load ramp before 11 am Pacific Standard Time (PST).

The CAISO also defines three categories of resources as well as the quantities of their respective capacities that can be used to serve ramp. Figure 3 illustrates the primary vs secondary net load and the three categories of resources.

- “Base Ramping” is used to serve both the primary and secondary net load ramps. These resources must be able to cycle or be able to start and stop quickly and are required to have little use limitations.
  - Examples of Base Ramping resources include combine cycle gas turbines (CCGT’s) and combustion turbines (peaters) with minimum start limitations.
- “Peak Ramping” resources serve only the primary net load ramp and are typically more constrained in their operating parameters, e.g. one start a day instead of two.
- “Super-Peak Ramping” resources are extremely use limited resources that are used for severe primary net load ramps, e.g. storage units.

Base Ramping resources can count in all three categories, while Peak Ramping can count as only Peak and Super-Peak resources. More information about the three categories can be found in the CAISO FRAC MOO tariff. These definitions are applied to the model as discussed later.

The CAISO defines a resources ability to ramp as effective flexible capacity (EFC) when counting resources for the CAISO’s resource adequacy (RA) program. The EFC is similar to the concept of net qualifying capacity (NQC) which is a resources ability to serve system peak as defined by the CAISO. For a unit with a startup of less than 90 minutes the EFC is defined as the average ramp rate times 180 minutes and cannot exceed the resource’s NQC. For a unit with a start time of more than 90 minutes the EFC is defined as the average ramp rate times 180 minutes bounded by the unit’s operational minimum (PMin) to NQC. Refer to the CAISO tariff for a more detailed description on the calculation for

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14 CAISO Tariff Section 40.10.3.
EFC.$^{15}$ This study utilized the CAISO published 2017 EFC list to derive the generators EFC and ramping categories.$^{16}$

Figure 3 Representation of Ramping$^{17}$

Loss of Load Expectation

The concept of loss of load expectation (LOLE) is used to allocate the cost of marginal capacity to time periods with the highest likelihood of capacity shortage. This method allows for the identification of periods in the year when loss of load due to capacity shortages has a higher chance of occurring versus others due to marginal demand. This can then be used to send price signals to customers in order to change load behavior during periods of time when the system is more likely to have an outage. The calculation of LOLE requires factoring into account different unit outages, renewable production, and load patterns. A stochastic reliability model is used to account for these factors. Figure 4 illustrates a comparison of the expected probability of peak load versus the expected available capacity. When the two curves overlap, an outage occurs due to insufficient capacity necessary to meet load. This comparison is performed for each hour of the year.

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$^{15}$ CAISO Tariff Section 40.10.4.

A similar distribution of ramp versus available flexible capacity also exists. However, the distribution of capacity that is able to ramp is different because certain resources such as nuclear generation, combined heat and power (CHP)\(^{18}\), renewable power, or other “must take” resources do not offer flexible capacity to meet ramping needs. The present study evaluates not only at peak load criteria, but ramp criteria as well.

**LOLE Methodology**

There is always a trade off in modeling between complexity and accuracy. First, the peak and ramp need can be served by the available physical capacity without regard to constraints associated with economic dispatch and transmission congestion. The resource characteristics must then be designed such that if enough are procured, the ramping needs can be meet. Second, the LOLE model assumes peak can be served by resources identified as NQC while the ramp can be served by resources identified as EFC. Third, solar and wind resources are modeled as shapes in the LOLE tool when calculating net load as opposed to modeling them as single capacity value (supply-side) resources. Fourth, the model assumes a resource can simultaneously serve both peak and ramp with the stack of

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\(^{18}\) Also known as qualifying facilities under Public Utility Regulatory Policies Act which requires the utilities to purchase their power.
resources always optimized. This means grid operations are satisfied until there are no more resources available. This is valid since the study is not evaluating unit dispatch or resource procurement.

The LOLE study uses a Monte Carlo simulation similar to that used in SCE’s RDW, but with the addition of a ramp need analysis.\textsuperscript{19} For each day in a year the model randomly draws hourly load, wind, and solar data and evaluates the draw. Both daily and hourly data is assessed to determine which days and hours have a probability of experiencing a LOLE from insufficient peak or ramping resources.

To obtain a large sample size the model takes thirty weather years of load, one year solar, and one year of wind data and samples five percent of all possible load, wind, and solar day combinations for each day in a year.\textsuperscript{20} Each sample is evaluated to determine the probability of not having sufficient resources to meet either the peak or ramp. Refer to Figure 5 for an illustration of the high level LOLE calculation. The graph represents a single draw in a single hour when solving for Peak LOLE. As the megawatt requirement for peak increases relative to resource availability, the probability of a LOLE occurring increases. The sum of the probabilities over the number of draws for the day will inform the daily LOLE curve.

**Figure 5 Loss of Load Expectation Methodology**

\[
LOLE_{Peak_t} = \frac{\sum (1 - ProbPeak_{t,i})}{Draws}
\]

Another way of understanding the calculation is shown in Figure 8 an illustrative example of a month with recorded LOLE. Figure 6 shows the “headroom”, which is available dispatchable generation minus the need, versus an array of forced outages. When the headroom curve falls below the forced

\textsuperscript{19} “Testimony of Southern California Edison Company in Support of its Application for Approval of its 2016 Rate Design Window Proposals”. SCE-1, A.16-09-003, (U338-E), Sept. 1, 2016.

\textsuperscript{20} See Silsbee, Nelson, et al., for background on method to develop a sample of net load forecasts.
outage lines a LOLE is recorded. More probability will be assigned to the hour for the day in the month the LOLE occurred the further bellow the max forced outage curve the headroom is.

Figure 6 Illustrative Example of LOLE Methodology for a single month

It is possible the sum of the daily probabilities will not equal 1 outage in 10 years (1 in 10), which is the targeted reliability level.\(^1\)\(^,\)\(^2\) Thus outages may result in a narrow or overly broad distribution of hours during the year. The reliability of the system was adjusted to yield a 1 in 10 outage to develop pricing periods that are reflective of the desired reliability level. This is done by increasing the load or decreasing the resource availabilities such that the sum of all the daily probabilities equals 1 in 10. This modeling effort applied the scaler to the load instead of the resources available.\(^3\) This is process is run separately for both peak and ramp. Once both 1 in 10 peak and ramp LOLE’s have been created, the two curves are normalized to a combined 1 in 10 using an exogenous variable that represents the split between peak and ramp LOLE. The modeler will need to develop a methodology that ensures the

\(^{21}\) The California Public Utility Commission established a 15% planning reserve margin, which is the additional reserves needed to yield a reliability level of 1 outage in 10 years. http://www.cpuc.ca.gov/RA/ See CPUC D. D.04-10-035

\(^{22}\) The model has discovered a 1 in 10 LOLE once the sum of all daily probabilities over all sample draws for the study year equals 0.1. The 0.1 is then multiplied by 10 represent the number of years and by the number of days in the study year. The final result should equal 1 which is 1 day in 10 years.

\(^{23}\) If the scaler was applied to the resources available it would have needed to be applied to the forced and maintenance outage schedules as well as the total available capacity. It was simpler to apply it to the two simulated needs.
exogenous weighting factor reflects a reasonable split between LOLE cause by peak vs LOLE caused by ramp. A reasonable split should reflect the justifiable constraint of the two needs against each other, e.g. the size of the annual peak vs the size of the largest annual ramp.

**LOLE model inputs**

Net Load required inputs are hourly shapes which included the following:

- Thirty years of simulated load from historical weather data;
- One year of solar generation; and
- One year of wind generation.

The thirty years of simulated load data is scaled such that the average of the thirty shapes produces an expected target energy. The yearly solar and wind energies should reflect the expected energies for the technologies in the study year. The yearly load, wind, and solar energies were derived from the 2016 LTPP planning assumptions for 2017-2026.\(^{24}\) The hourly solar and wind shapes were derived from recorded 2016 CAISO solar and wind generation.\(^{25}\) The thirty years of simulated load data represent the CAISO and were derived internally at SCE using historical weather data. A summary of load, wind, and solar data used in the study is shown in Table 1. Model assumes that net load cannot start below zero when calculating ramp.

**Table 1 Load, Wind, Solar Inputs\(^{26}\)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Expected Energy (GWh)</th>
<th>Expected Peak (MW)</th>
<th>Expected Peak Hr (PST)</th>
<th>Expected Ramp (MW)</th>
<th>Expected 3Hr Ramp (PST)</th>
<th>Wind (GWh)</th>
<th>Solar (GWH)</th>
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\(^{25}\) ABB, Velocity Suite – 2017

\(^{26}\) Peaks and ramps derived from average shapes that were scaled to the load, wind, and solar energies. Peaks are lower than those reported in the LTPP assumptions. Solar represents Solar PV and Solar Thermal.
The nonrenewable resources were derived from the CAISO 2017 NQC and EFC lists.\textsuperscript{27} Generation retirements, import limits, and renewable assumptions were derived from the 2016 LTTP planning assumptions.\textsuperscript{28} The generators’ forced outage and maintenance rates were assumed to be five percent respectively for all resources except renewables and imports.\textsuperscript{29} A maintenance schedule was derived assuming a certain percentage of annual available energy loss is due to maintenance. This is then distributed daily by weighting the expected daily peak load against the total peak capacity. This daily shape is then scaled linearly to EFC total capacity to ensure outage data between peak and ramp resources are correlated. A monthly curve of 10,000 forced outage possibilities is derived assuming a percentage of the time a generator has a probability of going offline. If a generator is assumed to go offline both its EFC and NQC are assumed to not be available.

Results

The following results were derived from the methodology discussed in the LOLE methodology section. As can be seen in Figure 7 the split between peak and ramp in 2018 was 75\% peak and 25\% ramp and in 2026 was 55\% peak and 45\% ramp. This split was developed by taking the max monthly average net load peak and ramp occurring during LOLE events in the respective LOLE calculations. The net load peak value was then multiplied by 115\% to simulate a planning reserve margin (PRM) and the ratio between the resulting net load peak and ramp was taken to determine the split between the 1 in 10 peak and the 1 in 10 ramp. This shift in LOLE from peak to ramp coincides with the declining load year over year while solar and wind are increasing.


\textsuperscript{29} This simplifying assumption will have an impact on results and if the study was being used for rate making purposes the generator outage rates would need to be refined.
Tables 2-4 show the monthly and hourly allocation of relative LOLE for 2018, 2020, and 2026 to show the changing LOLE allocation by year. In 2018 most of the LOLE was concentrated in the summer months but by 2026, as the ramp relative to the net load peak increased, the LOLE shifted towards ramp which is concentrated in the winter months.

This split between peak and ramp was determined by the exogenous weighting factor discussed above. This indicates the importance of the modeler having justification for the exogenous factors used in their study. It is important that the exogenous factor account for the potential shift in grid operation constraints. The winter months may become a more limiting factor for capacity due to increasing ramp and decreasing net load peak size from increasing RPS and declining resource availability due to potential generation retirements. Using the directionality and magnitude of the results, assists in the development of pricing periods to signal when to use or avoid energy demand.
Table 2 LOLE 2018

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LOLE due to Ramp: Represents the LOLE for the last hour of a three hour ramp.

LOLE due to Peak: The LOLE is attributed to peak and less hours with LOLE due to peak.

Table 3 LOLE 2020

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LOLE due to Ramp: Spreading to more months and hours in year, some ramp hours occur during peak LOLE times (Sept, Oct 19).

LOLE due to Peak: Less LOLE attributed to peak and less hours with LOLE due to peak.

30 All time stamps are anchored to a 2018 PST timestamp as is hour beginning, so hour 18 is 18:00-18:59. LOLE due to ramp represents the last hour of a three hour ramp, so the LOLE for hour 18 is for 16:00-18:59. In a rate design proceeding different rate pressures to customers may be applied to the three different hours to incentivize a smaller ramp.
Table 4 LOLE 2026

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LOLE due to Ramp: Spreading to more months and hours in year and magnitude of LOLE attributed to ramp increased

LOLE due to Peak: Only a couple hours in year are now attributed to peak, very concentrated in those few hours, only one hour in Sept attributed to ramp (Sept, Hr 18)

Alternate LOLE methodology

Since capacity is able to serve both peak and ramp, the combined 1 in 10 LOLE can be solved for in one step removing the need for an exogenous variable. The same methodology discussed previously is utilized, but, the LOLE is simultaneously evaluating for peak and ramp LOLE. This method is diagramed in Figure 8. Both peak and ramp needs are compared to their relative resource availabilities over the draws to determine the final 1 in 10 combined LOLE. The same concept of headroom is applied to this methodology, only the tool solves for the both needs simultaneously.
Similar to the previous methodology, if the initial run does not result in a 1 in 10 LOLE, the needs must be shifted. Since peak and ramp needs are being evaluated, both must be shifted by the same ratio. This ensures that the relative LOLE appropriately reflects which need has a higher probability of occurring. For example, if the ratio between the peak and ramp changes and a LOLE is distorted, then the relative probability of an LOLE event occurring misrepresents how much of the LOLE is attributed to one need over another.

Any LSE utilizing this LOLE approach must ensure that the resources being compared to the simulated needs are the total needs and total resources attributed to the LSE. Otherwise the ratio between the available resources and their needs will be incorrect, causing misappropriation of relative LOLE’s. As can be seen in the following results section, the LOLE may rapidly shift from one need to another. It has not been verified that the results of the following section represent the relative 1 in 10 LOLE of peak and ramp rather than a modeling artifact. Therefore, future study is required before implementing this method in rate making proceedings.

**Combined LOLE Results**

Relative LOLE’s for the years 2018-2026 were derived using the alternate LOLE methodology. In 2018, the study finds the amount of relative LOLE caused by 100% peak, but by 2026 the amount of relative LOLE is 100% ramp. The shift in contribution to relative LOLE from peak to ramp occurs from 2019 to 2021, as shown in in Figure 9. This occurrence can be attributed to the increasing ratio between
peak capacity and net load peak and the decreasing ratio between flexible capacity and net load ramp. Tables 5-7 show the monthly and hourly allocation of relative LOLE in 2018, 2020, and 2026.\textsuperscript{31}

Figure 9 System LOLE, Peak vs Ramp

\textsuperscript{31} For relative LOLE attributable to peak is the likelihood of not meeting load during the given hour. For LOLE attributable to ramping, it is the likelihood of failing to meet the ramp over a three hour period, ending at the hour in the table; in 2020, the November LOLE at hour 17, represents the hours 14 through 17.
Table 5 System LOLE Combined 2018

Table 6 System LOLE Combined 2020
Table 7 System LOLE Combined 2026

From these results it can be determined that relative LOLE’s primary contributor in later years is lack of ramping capacity as opposed to peaking capacity. The results also indicate that the LOLE will rapidly shift between the need for peak capacity to capacity that can ramp. If the results from this study, instead of the results discussed using the original LOLE methodology, were utilized, the LOLE split would cause a rapid shift in rate pressures to customers to incentives load behaviors.

An interesting result is the rapid shift from one need to another. This may be indicative of what type of capacity may be driving generation capacity need in the future; which, would lead to different periods to focus rate pressures in order to reduce cost. However, it may be too drastic of a price shift for ratepayer stability.

Also, it is likely that peak capacity will still be a system constraint in the future and therefore still needs to influence rates. Due to the lack of sophistication within the model, this approach needs further study to ensure or disprove this outcome of rapidly shifting needs before it can appropriately be applied for ratemaking purposes.
Conclusions

The results for 2018 show the primary driver of LOLE is peak related. In 2020, the influence of ramping appears in the LOLE, which occurs in the hours leading up to the peak related hours. For use in developing costing periods, this indicates that rates may need to include ramp to send a signal to the customer to improve grid reliability and avoid new system capacity additions. Another implication for developing costing periods is the LOLE contribution for ramp, while shown for an hour, is actually representative of a ramp that occurs over a three hour period. This results in an interesting design choice for which hours should be sent a price to reduce demand during a ramping period. Should all three hours be priced uniformly, is it only the last hour, or some type of shaping? A uniform application might result in a uniform decrease in load which would not impact the ramp over the three hour period. Applying the pricing to the last hour could result in the load being moved up 1 hour. While reducing the ramp over three hours, actually made the ramp worse over two hours. A careful examination of the loads and their price elasticity is required to alter the shape around the ramping LOLE period in order to reduce the slope. This could be achieved by price reductions prior to the ramping period to encourage demand which then graduates to higher prices to discourage demand. Where the price shift should occur during the ramping period is a topic for another study.

A surprising finding in the combined LOLE methodology was the rapid shift from 2019-2021 of LOLE being entirely driven by peak to being entirely driven by ramp. As this study was intended for proof of concept, the methodology and inputs need further refinement before the results can be used for ratemaking proceedings.

An issue of including ramp in a marginal capacity pricing study is that there are more solutions to solving the system ramp than just adding new flexible capacity. Instead of curtailing load, which is very expensive due to the value of lost service, renewable output can be curtailed which would reduce ramping need. If an on-peak time period was developed on the alternate 2026 LOLE results, it could result in a time period that is far too narrow. This could result in a price that exceeds the cost of curtailing renewable power, which would send the wrong economic price signal. In addition, very narrow pricing periods result in a shift which moves the LOLE to nearby hours, which in the next adjustment period, reverts back to the original definition resulting in cyclical changes to the TOU period definition.

The purpose of this study was to develop a methodological approach to understand the drivers of LOLE between ramping and peak needs. No actual need or rate making conclusions should be drawn from the presented results. This is a proof of concept study to that will continue to be improved. The
developed inputs were not vetted to ensure the validity of the split between LOLE peak and ramp for the years in which they occurred. Anyone utilizing the combined LOLE methodology must ensure the whole resource fleet available to the LSE is modeled in addition to the correct load, wind, and solar being attributed to the LSE.
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