SCE 2019 Rate Update

Association of Energy Engineers SoCal meeting
January 24, 2019
Estimated 2019 System Average Rate
- Bundled Service (cents/kWh) | Rate Levels include EITE & Climate Dividend

Preliminary rate level is estimated based on SCE’s latest forecast and is subject to change based on future CPUC decisions in various proceedings & market

Recent SAR History
January 2015 – 16.2 cents/kWh
January 2016 – 15.0 cents/kWh
January 2017 – 15.8 cents/kWh

* SCE’s alternate implementation proposal to address a possible delay in its 2019 ERRA implementation due to unsettled issues related to the Power Charge Indifference Adjustment (PCIA)
Estimated 2019 Class Average Rates
- Bundled Service (cents/kWh) | Rate Levels exclude EITE & Climate Dividend

Estimated 2019 rates reflect SCE’s newly adopted 2018 GRC Phase 2 revenue allocations.

Preliminary rate level is estimated based on SCE’s latest forecast and is subject to change based on future CPUC decisions in various proceedings & market

<table>
<thead>
<tr>
<th>Service Type</th>
<th>Jan 2018</th>
<th>1st Half - 2019</th>
<th>% Change</th>
<th>Jan 2018 % of SAR</th>
<th>1st Half - 2019 % of SAR</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Residential</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>19.5</td>
<td>19.8</td>
<td>1.6%</td>
<td>116%</td>
<td>118%</td>
</tr>
<tr>
<td>Small C&amp;I (&lt; 20 kW)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TC-1</td>
<td>19.1</td>
<td>18.9</td>
<td>-0.9%</td>
<td>114%</td>
<td>113%</td>
</tr>
<tr>
<td>TOU-GS-1</td>
<td>17.8</td>
<td>17.6</td>
<td>-0.9%</td>
<td>106%</td>
<td>105%</td>
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<tr>
<td>Medium C&amp;I (20 kW - 200 kW)</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>TOU-GS-2</td>
<td>18.1</td>
<td>18.0</td>
<td>-0.9%</td>
<td>108%</td>
<td>107%</td>
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<tr>
<td>Medium C&amp;I (200 kW - 500 kW)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-GS-3</td>
<td>16.0</td>
<td>15.9</td>
<td>-0.9%</td>
<td>96%</td>
<td>95%</td>
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<tr>
<td><strong>Total Lighting/Small/Medium C&amp;I</strong></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>TOU-GS-1</td>
<td>17.5</td>
<td>17.3</td>
<td>-0.9%</td>
<td>105%</td>
<td>103%</td>
</tr>
<tr>
<td>Large C&amp;I (Sec)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-8-SEC</td>
<td>14.2</td>
<td>14.2</td>
<td>-0.3%</td>
<td>85%</td>
<td>84%</td>
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<tr>
<td>Large C&amp;I (Pri)</td>
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<tr>
<td>TOU-8-PRI</td>
<td>12.9</td>
<td>12.8</td>
<td>-0.3%</td>
<td>77%</td>
<td>76%</td>
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<td>Large C&amp;I (Sub)</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-8-SUB</td>
<td>9.0</td>
<td>9.0</td>
<td>-0.3%</td>
<td>54%</td>
<td>53%</td>
</tr>
<tr>
<td><strong>Total Large C&amp;I</strong></td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-8-SEC-S</td>
<td>14.5</td>
<td>14.4</td>
<td>-0.9%</td>
<td>87%</td>
<td>86%</td>
</tr>
<tr>
<td>TOU-8-PRI-S</td>
<td>13.8</td>
<td>13.7</td>
<td>-0.9%</td>
<td>83%</td>
<td>82%</td>
</tr>
<tr>
<td>TOU-8-SUB-S</td>
<td>9.0</td>
<td>9.0</td>
<td>0.0%</td>
<td>54%</td>
<td>54%</td>
</tr>
<tr>
<td><strong>Total Large Power</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-8-SEC-S</td>
<td>14.5</td>
<td>14.4</td>
<td>-0.9%</td>
<td>87%</td>
<td>86%</td>
</tr>
<tr>
<td>TOU-8-PRI-S</td>
<td>13.8</td>
<td>13.7</td>
<td>-0.9%</td>
<td>83%</td>
<td>82%</td>
</tr>
<tr>
<td>TOU-8-SUB-S</td>
<td>9.0</td>
<td>9.0</td>
<td>0.0%</td>
<td>54%</td>
<td>54%</td>
</tr>
<tr>
<td><strong>Total Ag &amp; Pumping</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-PA-2</td>
<td>14.8</td>
<td>14.7</td>
<td>-0.9%</td>
<td>89%</td>
<td>87%</td>
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<tr>
<td>TOU-PA-3</td>
<td>12.0</td>
<td>12.2</td>
<td>1.4%</td>
<td>72%</td>
<td>73%</td>
</tr>
<tr>
<td><strong>Total Large Power</strong></td>
<td>13.6</td>
<td>13.6</td>
<td>0.0%</td>
<td>81%</td>
<td>81%</td>
</tr>
<tr>
<td><strong>Total Street &amp; Area Lighting</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Street Lighting</td>
<td>18.5</td>
<td>18.8</td>
<td>1.6%</td>
<td>111%</td>
<td>112%</td>
</tr>
<tr>
<td>Standby (Sec)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-8-SEC-S</td>
<td>14.5</td>
<td>14.4</td>
<td>-0.9%</td>
<td>87%</td>
<td>86%</td>
</tr>
<tr>
<td>Standby (Pri)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-8-PRI-S</td>
<td>13.8</td>
<td>13.7</td>
<td>-0.9%</td>
<td>83%</td>
<td>82%</td>
</tr>
<tr>
<td>Standby (Sub)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOU-8-SUB-S</td>
<td>9.0</td>
<td>9.0</td>
<td>0.0%</td>
<td>54%</td>
<td>54%</td>
</tr>
<tr>
<td><strong>Total Standby</strong></td>
<td>10.4</td>
<td>10.4</td>
<td>-0.3%</td>
<td>62%</td>
<td>62%</td>
</tr>
<tr>
<td><strong>TOTAL BUNDLED</strong></td>
<td>16.7</td>
<td>16.8</td>
<td>0.3%</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>
March 1, 2019 “Pot of Stew”
(Not a comprehensive list of all rate change components)

**RECIPE**
2016 Rate Design Window (D.18-07-006) adopted:
- New Time-of-Use (TOU) Periods
- Critical Peak Pricing (CPP) expansion; reduced credits/charges phased-in over two years
- Real Time Pricing (RTP) changes and add Time Related Demand (TRD) charges

**RECIPE**
Transportation Electrification (D.18-05-040) adopted:
- New Electric Vehicles (EV) rates for Commercial & Industrial (C&I) customers

**RECIPE**
Time-Of-Use (TOU):
- Grandfathered eligibility for solar Net-Energy Metering (NEM) customers

**RECIPE**
2018 GRC Phase 2 adopted:
- New rate options: D and E
- Elimination of Super Off-Peak (SOP) rates for Ag customers
- New optional 5-8 p.m. peak period rates for Ag customers
- Economic Development Rates (EDR)

**RECIPE**
2018-22 Demand Response (DR) Program (D.17-12-003) adopted:
- Phase in reduced Base Interruptible Program (BiP) incentive payments below current levels by about 10% per year over the next 4 years.

Energy for What’s Ahead®
New Time-Of-Use (TOU) Periods

- Shifts daily “peak” period to 4-9 p.m. (currently noon to 6 p.m.)
- Introduces “super off-peak” period from 8 a.m.-4 p.m. on all Winter days
- Introduces TOU to weekend charges (currently all weekend hours are “off-peak”)
- Maintains existing seasonal definitions (Summer: June-Sept; Winter: Oct-May)

The Time-of-Use (TOU) peak period applies to “standard” TOU rates defined as follows: TOU-8, TOU-GS-3, TOU-GS-2, TOU-GS-1, TOU-PA-3, & TOU-PA-2. CPP events occur on weekdays and will take place 12 times per year.
2018 GRC Phase 2 + Other Key Changes

<table>
<thead>
<tr>
<th>New Rate Options</th>
<th>Critical Peak Pricing (CPP)</th>
<th>Real Time Pricing (RTP)</th>
<th>Economic Development Rate (EDR)</th>
</tr>
</thead>
</table>
| • Option D (replacement for Option B Base Rate)  
  • Includes the addition of a winter mid-peak distribution TRD (non-holiday weekdays only)  
  • Maintains existing eligibility requirements | • Overview  
  • CPP offers a discount on summer electricity rates in exchange for higher prices during 12 CPP event days per year between 4 p.m. and 9 p.m., usually occurring on the hottest summer days | • Reduce from 5 to 3 summer weekday pricing categories  
  • Introduces year-round Time Related Demand (TRD) charges | • Offers a standard 12% discount – 5 year contract  
  • 200 MW cap |}

• Option E* (replacement for Options A & R Optional Rates)  
  • Includes a new generation TRD charge in the summer on-peak and winter mid-peak (non-holiday weekdays only)  
  • Customers w/ DERs are exempt from Standby if served on this rate option

• New Optional Ag & Pump Rate  
  • In addition to the 4-9pm standard option, a 5-8pm option will be available

• Default  
  • Applies to all General Service and Large Ag & Pump customers; departing load customers not eligible  
  • Default to begin Mar. 2019 for all eligible accounts; annual default will start in October of 2020 for eligible accounts thereafter  
  • CPP is an optional rate; there is a 60-day period to Opt Out of CPP before defaulting

* Option E is limited to customers w/ qualifying technologies, including technologies currently eligible for TOU-8, Options A and R and BTM paired storage (solar+storage) and standalone storage
Option D vs. E
(Illustrative TOU-GS-2 Rate Examples)

<table>
<thead>
<tr>
<th>Energy Charge - ¢/kWh</th>
<th>Option D</th>
<th>Option E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer On-Peak</td>
<td>10.6</td>
<td>46.4</td>
</tr>
<tr>
<td>Summer Mid-Peak</td>
<td>9.8</td>
<td>16.0</td>
</tr>
<tr>
<td>Summer Off-Peak</td>
<td>7.3</td>
<td>11.0</td>
</tr>
<tr>
<td>Winter Mid-Peak</td>
<td>8.7</td>
<td>14.6</td>
</tr>
<tr>
<td>Winter Off-Peak</td>
<td>7.8</td>
<td>8.2</td>
</tr>
<tr>
<td>Winter Super-Off-Peak</td>
<td>6.0</td>
<td>7.3</td>
</tr>
</tbody>
</table>

| Customer Charge - $/month | 125.25 | 125.25 |

| Facilities Related Demand Charge (FRD) - $/kW | 11.41 | 8.19  |

<table>
<thead>
<tr>
<th>Time Related Demand Charge (TRD) - $/kW</th>
<th>Option D</th>
<th>Option E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer On-Peak</td>
<td>26.81</td>
<td>3.46</td>
</tr>
<tr>
<td>Summer Mid-Peak</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Winter Mid-Peak</td>
<td>6.98</td>
<td>0.74</td>
</tr>
<tr>
<td>Winter Off-Peak</td>
<td>0.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>

| CPP Event Energy Charge - ¢/kWh | 40.0 | 40.0 |
| Summer Non-Event Demand On-Peak Credit - $/kW | (3.42) | (3.42) |

Option D recovers more costs via demand charges
(tends to benefit higher load factor customers)

Option E recovers more costs via energy charges
(tends to benefit lower load factor / DER customers)
Rate Plan Comparison Tool (RPCT)

- SCE has launched a new tool with rate analysis results available directly to customers
- Visit [www.sce.com/ratetool](http://www.sce.com/ratetool) and login with your MyAccount credentials
Appendix
Acronyms

A = Application
Ag = Agricultural
B = Billion
BA = Balancing Account
BIP = Base Interruptible Program
BRRBA = Base Revenue Requirement Balancing Account
CARE = California Alternate Rates for Energy
CCA = Community Choice Aggregation
C&I = Commercial & Industrial
CPP = Critical Peak Pricing
CPUC/Commission = California Public Utilities Commission
D = Decision
DA = Direct Access
DR = Demand Response
EDR = Economic Development Rate
EITE = Emissions Intensive and Trade Exposed
ERRA = Energy Resource Recovery Account
F&PP = Fuel and Purchased Power
FERC = Federal Energy Regulatory Commission
GRC = General Rate Case
kW = kilowatt
kWh = kilowatt hour
M = Million
MPB = Market Price Benchmark (MPB)
MMBtu = Million British Thermal Units
PCIA = Power Charge Indifference Adjustment
RTP = Real Time Pricing
SCE = Southern California Edison
SAR = System Average Rate
SONGS = San Onofre Nuclear Generation Station
TOU = Time-of-Use
TRD = Time Related Demand
**The “Duck Curve”**

**Duck’s Belly**
- In Spring, the net load curves produce a “belly” appearance in the mid-afternoon.
- Due to low demand and the influx of renewables, oversupply results, which can lead to overgeneration.
- During oversupply times, wholesale energy prices can be very low and even go negative.

**Duck’s Neck**
- In the late afternoon/early evening hours, the net load curves quickly ramp up to produce an “arch” similar to the neck of a duck.
- Ramp (aka flexible generation capacity) is attributed to demand peaks when the sun goes down and solar generation tapers off.
- As more renewable resources come online, the ramp gets steeper.
## Time-of-Use Period Change

<table>
<thead>
<tr>
<th>TOU Period</th>
<th>Season</th>
<th>Current</th>
<th>New</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-Peak</td>
<td>Summer</td>
<td>Weekdays: 12pm-6pm</td>
<td>Weekdays: 4-9pm</td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>Summer</td>
<td>Weekdays: 8am-12pm; 6pm-11pm</td>
<td>Weekends: 4-9pm</td>
</tr>
<tr>
<td></td>
<td>Winter</td>
<td>Weekdays: 8am-9pm</td>
<td>Weekdays and Weekends: 4-9pm</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>Summer</td>
<td>Weekdays: 11pm-8am Weekends: All hours</td>
<td>Weekdays and Weekends: All hours except 4-9pm</td>
</tr>
<tr>
<td></td>
<td>Winter</td>
<td>Weekdays: 9pm-8am Weekends: All hours</td>
<td>Weekdays and Weekends: 9pm-8am</td>
</tr>
<tr>
<td>Super-Off-Peak</td>
<td>Winter</td>
<td>N/A</td>
<td>Weekdays and Weekends: 8am-4pm</td>
</tr>
</tbody>
</table>
Rate Proceeding Updates
- 2019 Energy Resource Recovery Account (ERRA) | A.18-05-003

**Status / Implementation**

Current Status: Filed Update Testimony on Nov. 7, 2018 to update latest sales forecast assumptions
Implementation: Requested January 1, 2019 (likely Q2 2019)

**Highlights**

1. SCE requested approval of a 2019 ERRA revenue requirement of $4.785B
   - Increase of ~$999M from SCE’s June forecast filing
   - Increase of ~$209M over current authorized ERRA rate levels

2. Main drivers:
   - Significant ERRA under-collection due to July/August 2018 market price spikes
   - Increased forecast gas and power prices for 2019 (May: $2.26/MMBtu -> Nov: $2.51/MMBtu)

3. SCE proposed to assign a pro-rata (~23%) share of the 2018 ERRA Undercollection to 2019 departing load customers (see next slide)

4. The 2019 semi-annual California Residential Climate Credit is set at $33 per household
Rate Proceeding Updates
- Power Charge Indifference Adjustment (PCIA) | R.17-06-026

Status / Implementation

Current Status: CPUC approvals received
Implementation: Requested January 1, 2019 (likely Q2 2019 as 5 Applications to Re-hear D.18-10-019 filed)

Highlights

1. PCIA Exemption for CCA and DA CARE and Medical Baseline Customers

**ISSUE:** Departing load CARE and Medical Baseline customers receive a “double discount” because SCE already provides the full discount through their delivery rate.
Bundled service CARE and Medical Baseline customers have never been exempt from the same PCIA costs, which are included in their generation rate.

**D.18-07-009:** Eliminates the PCIA exemption by 1/1/19 to avoid continuing cost shifts to bundled service customers.

2. Reform PCIA Methodology

**ISSUE:** Current PCIA methodology is outdated and does not fairly apportion SCE’s generation procurement costs between bundled and departing load customers.

**D.18-10-019:**
(1) Revises inputs to the Market Price Benchmark (MPB) used to calculate the PCIA
(2) Caps future PCIA increases to 0.5¢/kWh per year, starting in 2020
(3) Adopts a true-up mechanism consistent with ERRA proceeding
(4) PCIA represents about $420M/year for all departing load customers
(5) Revises allocation of PCIA revenues to the various rate groups
Rate Proceeding Updates
- 2018 General Rate Case (GRC) Phase 1 | A.16-09-001

Status / Implementation

Current Status: Pending CPUC approval (application filed Sept. 1, 2016)
Implementation: TBD – 1st Half 2019

Highlights

1. Requested 2018 base revenue requirement of $5.534B, $106M or 0.38% decrease over presently authorized rates

2. Requested post test year increases: $431M (7.2%) in 2019 and $503M (9.4%) in 2020 over presently authorized rates


* Fed Income Tax Legislation updates filed Feb. 16, 2018
Rate Proceeding Updates
- 2018 General Rate Case (GRC) Phase 2 | A.17-06-030

Status / Implementation

Current Status: Case fully settled and Final Decision (D.18-11-027) issued on Nov. 29, 2018
adopting all revenue allocation and rate design proposals for all customer classes
Implementation: March 1, 2019

Highlights

Key Changes
1. New rate designs using updated TOU periods
2. Introduction of time-differentiated distribution in rates
   - Significantly less recovery via non-coincident demand charges (“FRD”) in non-residential rates
3. Introduction of flexible capacity price signals in rates
   - Address duck curve “ramp” issues by including a capacity price signal in winter mid-peak period
4. Provide a menu of rate options; including default Critical Peak Pricing and new rate options for customers adopting DERs

Key Takeaways
1. Customers whose usage is relatively less during peak periods or who can avoid usage in the new high cost periods (4-9pm, winter ramp) will see the largest benefit in terms of revenue allocation (e.g., 9-5 C&I customers, schools, etc.)
2. Customers whose usage is relatively more during peak periods or who cannot avoid usage in the new high cost periods will see the largest increases in terms of revenue allocation (e.g., residential, streetlights)