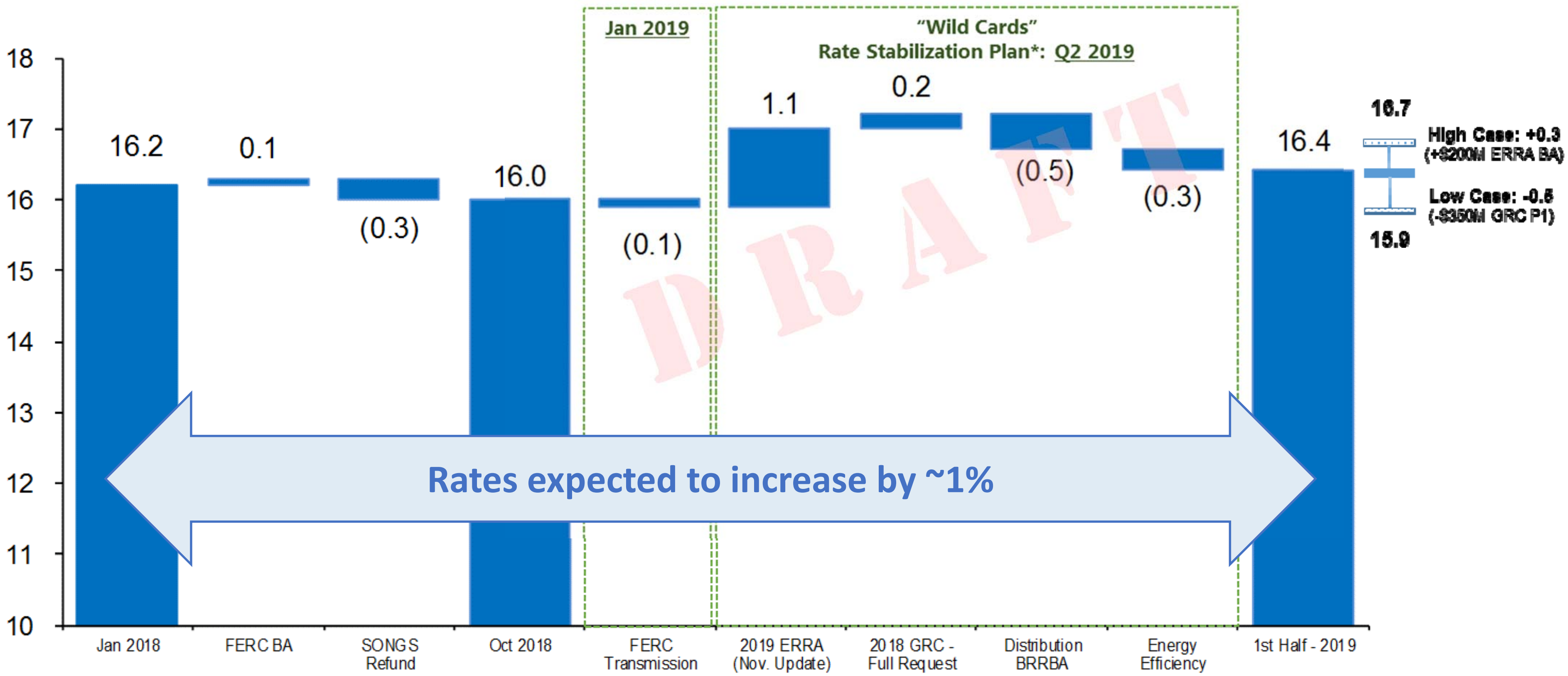
SCE 2019 Rate Update

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



* 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)

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

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

Estimated 2019 Class Average Rates

- Bundled Service (cents/kWh) | Rate Levels exclude 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

		Jan 2018	1st Half - 2019	% Change	Jan 2018 % of SAR	1st Half - 2019 % of SAR
Total Residential	Residential	19.5	19.8	1.6%	116%	118%
Small C&I (< 20 kW)	TOU-GS-1	17.8	17.6	-0.9%	106%	105%
Traffic Control	TC-1	19.1	18.9	-0.9%	114%	113%
Medium C&I (20 kW - 200 kW)	TOU-GS-2	18.1	18.0	-0.9%	108%	107%
Medium C&I (200 kW - 500 kW)	TOU-GS-3	16.0	15.9	-0.9%	96%	95%
Total Lighting/Small/Medium C&I	Total LSMP	17.5	17.3	-0.9%	105%	103%
Large C&I (Sec)	TOU-8-SEC	14.2	14.2	-0.3%	85%	84%
Large C&I (Pri)	TOU-8-PRI	12.9	12.8	-0.3%	77%	76%
Large C&I (Sub)	TOU-8-SUB	9.0	9.0	-0.3%	54%	53%
Total Large C&I	Total Large Power	12.3	12.3	-0.3%	74%	73%
Small Ag & Pump (<200 kW)	TOU-PA-2	14.8	14.7	-0.9%	89%	87%
Large Ag & Pump (≥ 200 kW)	TOU-PA-3	12.0	12.2	1.4%	72%	73%
Total Ag & Pumping	Total Ag & Pumping	13.6	13.6	0.0%	81%	81%
Total Street & Area Lighting	Street Lighting	18.5	18.8	1.6%	111%	112%
Standby (Sec)	TOU-8-SEC-S	14.5	14.4	-0.9%	87%	86%
Standby (Pri)	TOU-8-PRI-S	13.8	13.7	-0.9%	83%	82%
Standby (Sub)	TOU-8-SUB-S	9.0	9.0	0.0%	54%	54%
Total Standby	Total Standby	10.4	10.4	-0.3%	62%	62%
TOTAL BUNDLED	TOTAL BUNDLED	16.7	16.8	0.3%	100%	100%

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

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

Transportation Electrification (D.18-05-040) adopted:

- New Electric Vehicles (EV) rates for Commercial & Industrial (C&I) customers

RECIPE

Time-Of-Use (TOU):

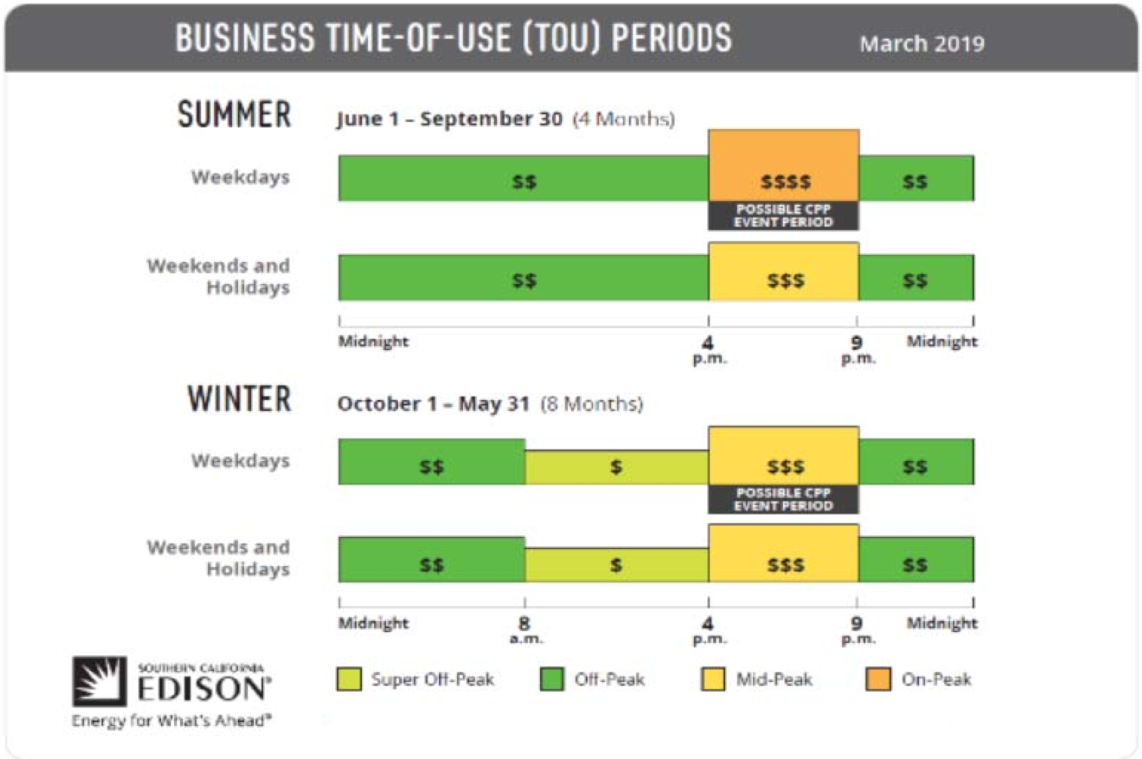
- Grandfathered eligibility for solar Net-Energy Metering (NEM) customers

RECIPE

2018-22 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.

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.

Part of March 2019 Consolidated Rate Change

2018 GRC Phase 2 + Other Key Changes

New Rate Options

- 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

- 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

Critical Peak Pricing (CPP)

- 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

- 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

Real Time Pricing (RTP)

- Reduce from 5 to 3 summer weekday pricing categories

- Introduces year-round Time Related Demand (TRD) charges

Economic Development Rate (EDR)

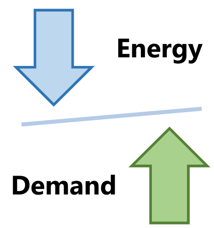
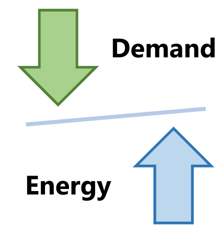
- Offers a standard 12% discount – 5 year contract

- 200 MW cap

- Eligible accounts must be ≥ 150kW non-residential, non-government accounts (max of 20 customers can participate w/loads less than 150kW)

* 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)

	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)*
		
Energy Charge - ¢/kWh		
Summer On-Peak	10.6	46.4
Summer Mid-Peak	9.8	16.0
Summer Off-Peak	7.3	11.0
Winter Mid-Peak	8.7	14.6
Winter Off-Peak	7.8	8.2
Winter Super-Off-Peak	6.0	7.3
Customer Charge - $/month	125.25	125.25
Facilities Related Demand Charge (FRD) - $/kW	11.41	8.19
Time Related Demand Charge (TRD) - $/kW		
Summer On-Peak	26.81	3.46
Summer Mid-Peak	0.00	0.00
Winter Mid-Peak	6.98	0.74
Winter Off-Peak	0.00	0.00
CPP Event Energy Charge - ¢/kWh	40.0	40.0
Summer Non-Event Demand On-Peak Credit - $/kW	(3.42)	(3.42)

Rate Plan Comparison Tool (RPCT)

- SCE has launched a new tool with rate analysis results available directly to customers
- Visit www.sce.com/ratetool and login with your MyAcount credentials

Rate Plan Comparison Tool for Businesses

Find out which rate plan is best for your bottom line. Use the tool to get a custom comparison between your current rate plan and other rate plan options.

Important Rate Plan Changes are Coming

Starting in **March 2019**, there will be rate plan changes that may affect your business. Use the Rate Plan Comparison Tool below to find out how your account(s) are affected.

Time-of-use (TOU) Peak Periods are Changing.

Lowest energy prices until 4 p.m. every day

Learn more about TOU changes >

Some Businesses will be automatically enrolled in Critical Peak Pricing (CPP)

Check out the program details to see if CPP can help lower your energy costs.

Learn more about CPP >

Be sure to update your contact preferences so that you receive notifications for CPP events.

Use the Tool to Compare Your Rate Options

- Get estimates based on your past usage.
- See how your monthly bills and average seasonal costs, could change with different rate plans.
- Choose and switch plans now.

Note: Your service account(s) must have 12 months of usage.

Use the Rate Plan Comparison Tool >

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

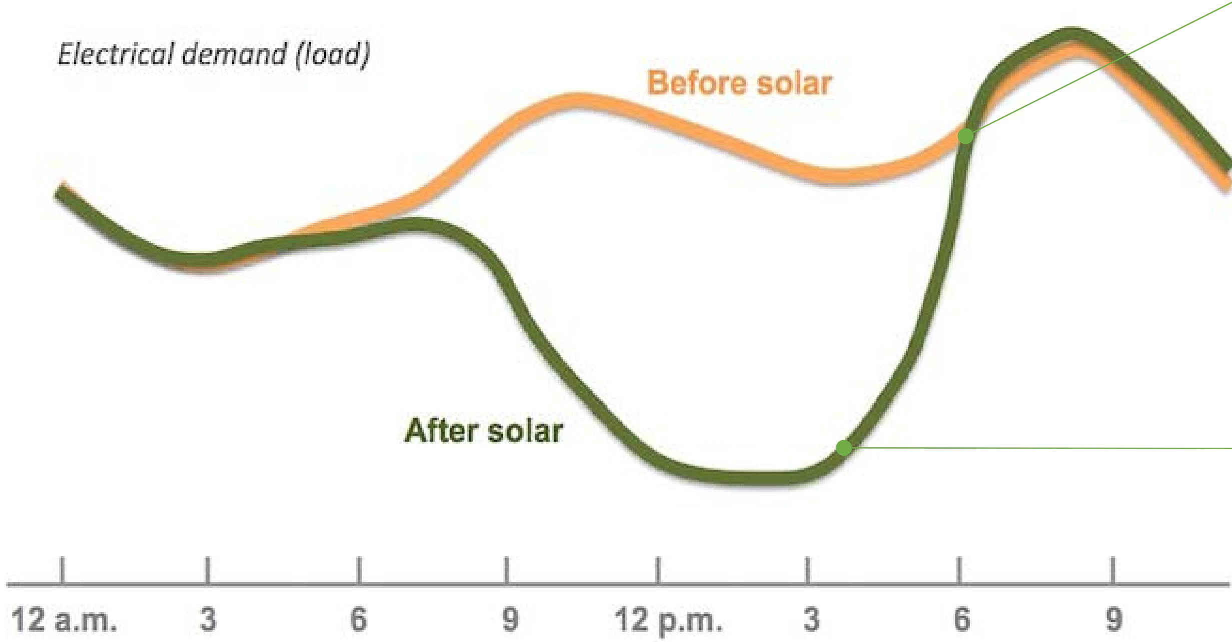
SAR = System Average Rate

SONGS = San Onofre Nuclear Generation Station

TOU = Time-of-Use

TRD = Time Related Demand

The “Duck Curve”



Duck’s Neck

- In the late afternoon / early evening hours, the net load curves quickly *ramps* 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

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

Time-of-Use Period Change

Part of March 2019 Consolidated Rate Change

TOU Period	Season	Current	New
On-Peak	Summer	Weekdays: 12pm-6pm	Weekdays: 4-9pm
Mid-Peak	Summer	Weekdays: 8am-12pm; 6pm-11pm	Weekends: 4-9pm
	Winter	Weekdays: 8am-9pm	Weekdays and Weekends: 4-9pm
Off-Peak	Summer	Weekdays: 11pm-8am Weekends: All hours	Weekdays and Weekends: All hours except 4-9pm
	Winter	Weekdays: 9pm-8am Weekends: All hours	Weekdays and Weekends: 9pm-8am
Super-Off-Peak	Winter	N/A	Weekdays and Weekends: 8am-4pm

Rate Proceeding Updates

- 2019 Energy Resource Recovery Account (ERRA) | A.18-05-003

ERRA
Forecasts fuel & purchased power expenses for the upcoming year

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

PCIA Charge
A charge that is applied to departing load customers and is designed to maintain bundled service customer indifference to departing load and CCA formation.

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

GRC Phase 1
Forecasts amount of money it takes to operate the utility (i.e., O&M, capital expenditures) needed over a 3-year period (e.g. 2018-2020); Excludes fuel/purchased power, transmission revenues, and certain other costs.

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
3. Reflected reductions resulting from the Federal Income Tax Legislation (aka The Tax Cuts and Jobs Act enacted on Dec. 22, 2017)*

* Fed Income Tax Legislation updates filed Feb. 16, 2018

Rate Proceeding Updates

- 2018 General Rate Case (GRC) Phase 2 | A.17-06-030

GRC Phase 2
Ratesetting Phase; Allocation of the authorized revenue requirement (all CPUC jurisdictional) across customer classes; Does not result in any overall revenue changes, only reallocation of revenues between customer classes and rate designs.

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)