CPUC Rate Forum

Russ Garwacki
Director of Pricing Design
Southern California Edison

Rate Design Forum Questions 1 and 2 –

1. What share of total generation capacity costs are driven by system-level peak demands? How much of that share is driven by the top 50 to 100 hours of demand? How much by other summer peak hours?
2. What share of total generation capacity costs are driven by system level ramping needs?

		Summer			Winter			
		On-Peak	**Mid-Peak**	**Off-Peak**	**Mid-Peak**	**Off-Peak**	**Super-Off Peak**	**$/kW-Year**
2015 GRC	**Total Combined**	83.5%	12.6%	3.8%	0.0%	0.0%	0.0%	$ 124.20
2018 GRC	**Total Combined**	71.5%	4.6%	0.2%	23.6%	0.0%	0.0%	$ 146.85
	- Peak	93.5%	6.1%	0.3%	0.1%	0.0%	0.0%	$ 94.40
	- Ramp	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	$ 52.45

* TOU periods differ between 2015 and 2018 GRC proposal.

Rate Design Forum Question #3 –

How should the portion of system level infrastructure costs that are time-dependent generally be recovered in rates? How about the portion associated with minimum loads? How does this cost allocation work in practice?

- Time dependent (aka “peak”) costs should be recovered either via time-differentiated demand and/or energy charges.
- The “minimum load” (aka “grid”) question is trickier – do we recover revenue from customers as a flat access cost or proportionately based on consumption, or peak demand, or some combination thereof? Since the bulk of the IOUs year to year investment is geared towards maintenance of this “minimum load” reliability, this is the core question.
- SCE’s 2018 GRC Phase 2 proposed recovery of distribution costs is about 75% non-TOU and 25% TOU based (for the 20-200 kW GS-2 rate group).
- The larger the aggregation point (e.g. transmission) the networked system necessarily has higher reserve margins to account for “N-1” reliability concerns (flexibility during locational outages).

Rate Design Forum Question #4 -

- System-level assets, such as generation and transmission facilities, serve the loads of thousands or millions of customers. Given the high degree of load diversity at the system level, do monthly coincident demand charges fairly and accurately allocate time-dependent costs to customers with variable or erratic loads?
- Would daily coincident demand charges or volumetric TOU (and/or dynamic) rates allocate costs more accurately?
- Compare and contrast the three options. [What are the data for the summer monthly coincident peak demands, sum of individual summer monthly peak-period maximum demands, and sum of individual average peak-period demands? Are coincident peaks closer to sum of max or sum of avg?]

Rate Design Forum Question #4 - continued
- Initial Draft Analysis

Spearman Correlation Coefficients for 20-200 kW General Service Customers

Cost Parameter	Annual Usage	Summer Usage	Summer On-Peak Usage (4-9 p.m.)	CPP Event Usage	Annual Peak Demand	Summer Monthly Non-coincident Peak Demand	Summer Monthly Non-coincident Peak Demand - On-Peak (4-9 p.m.)
Demand at "Gross" System Peak @4 p.m. - September 8, 2015	0.81	0.84	0.81	0.82	0.73	0.78	0.82
Demand at "Net" System Peak @8 p.m. - September 8, 2015	0.85	0.87	0.92	0.92	0.61	0.69	0.79

Time differentiate Distribution? TOU Energy/Demand?

CPP or simply TOU?

The correlations are quite strong across most of the alternatives under consideration.

Rate Design Forum Question 5 (Bonus Question!!) –

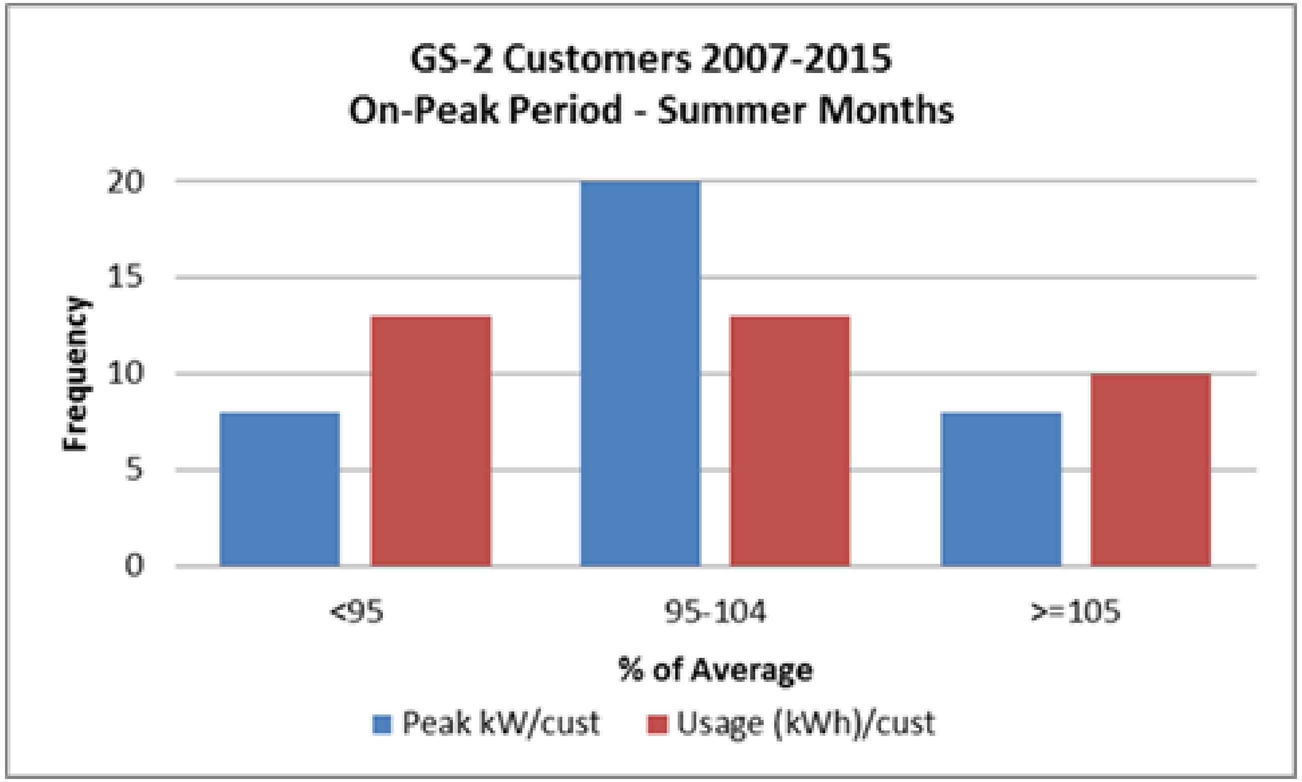
Would more pricing periods per day, including a narrow 2- or 3-hour summer “super-peak” TOU period, improve the accuracy of coincident demand charge or TOU rates? (As one example, Spanish utilities have up to 6 pricing periods during peak season).

- Yes, that would be a logical outcome if prices were known. Other considerations:
  - More TOU periods add complexity and have diminishing returns. For example, when the CAISO explored sub-LAP prices a few years ago, they concluded that there was not enough price differential to warrant the additional complexity with area pricing.
  - What if the narrow TOU periods are “off” by an hour? This would be much more significant for a narrow 2-hour peak period definition versus a broader 5-hour peak period definition. A broader definition also reduces the chance of having to change TOU periods in the future.

Rate Design Forum – Consider Revenue/Bill Stability

Does a rate structure that is more dependent on energy or demand lead to greater bill volatility?

As revenue becomes more concentrated in the hot summer months, the utility revenue (and customer bills) are more volatile under rate structures that rely more on energy charges. That's because there is generally more monthly variability with Cooling Degree Days (which drives energy usage) versus peak temperatures (which drives peak demand).



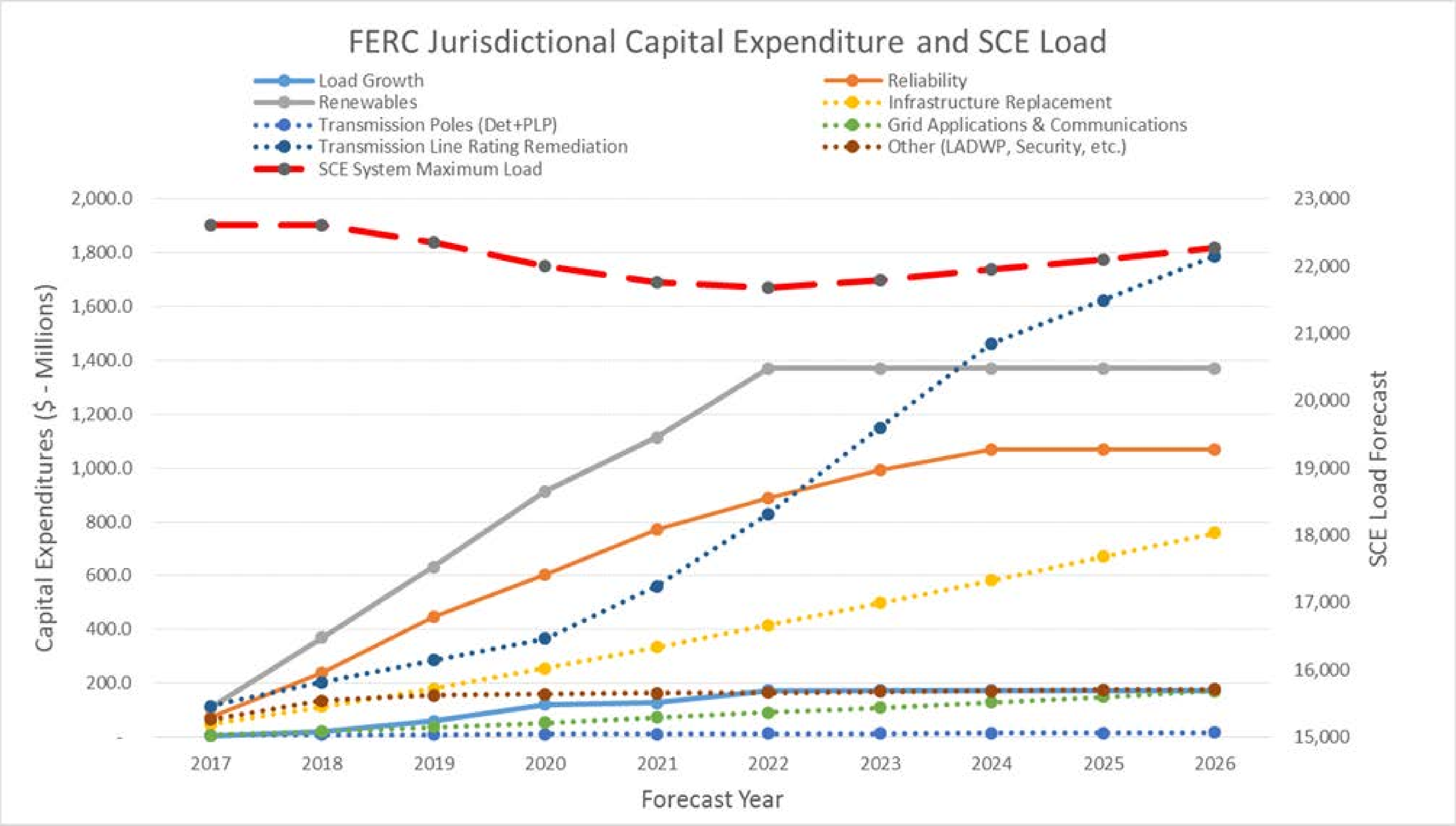
Normalized historical energy/demand billing determinant distributions

SCE – Transmission Appendix

SCE's 2016 TOU Rate Design Window (A.16-07-003, Rebuttal Testimony)

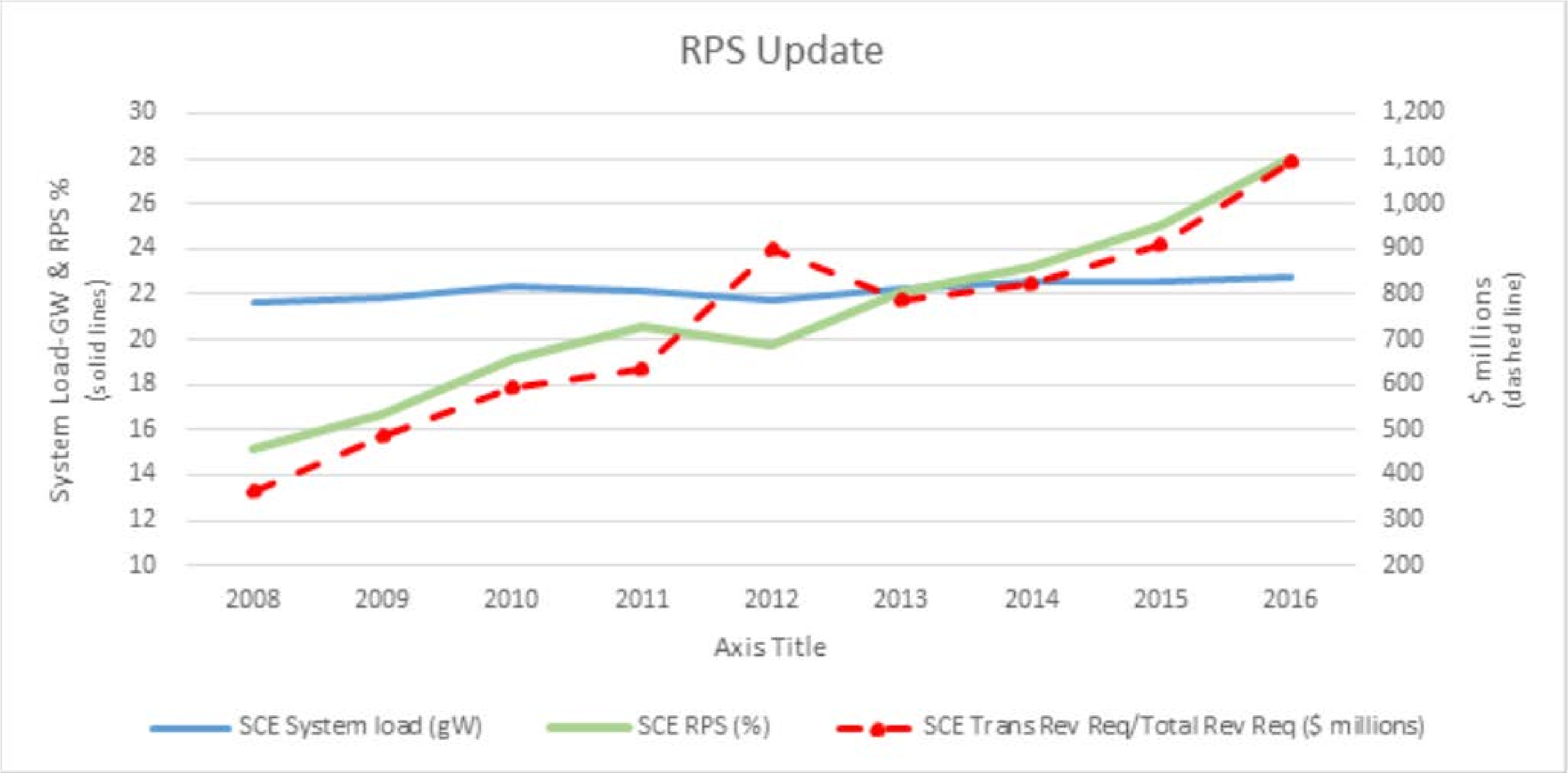
Transmission Cost Drivers #1

Forecast of Transmission System Capital Expenditure ($-Millions) by Program and SCE System Peak Load (MW)



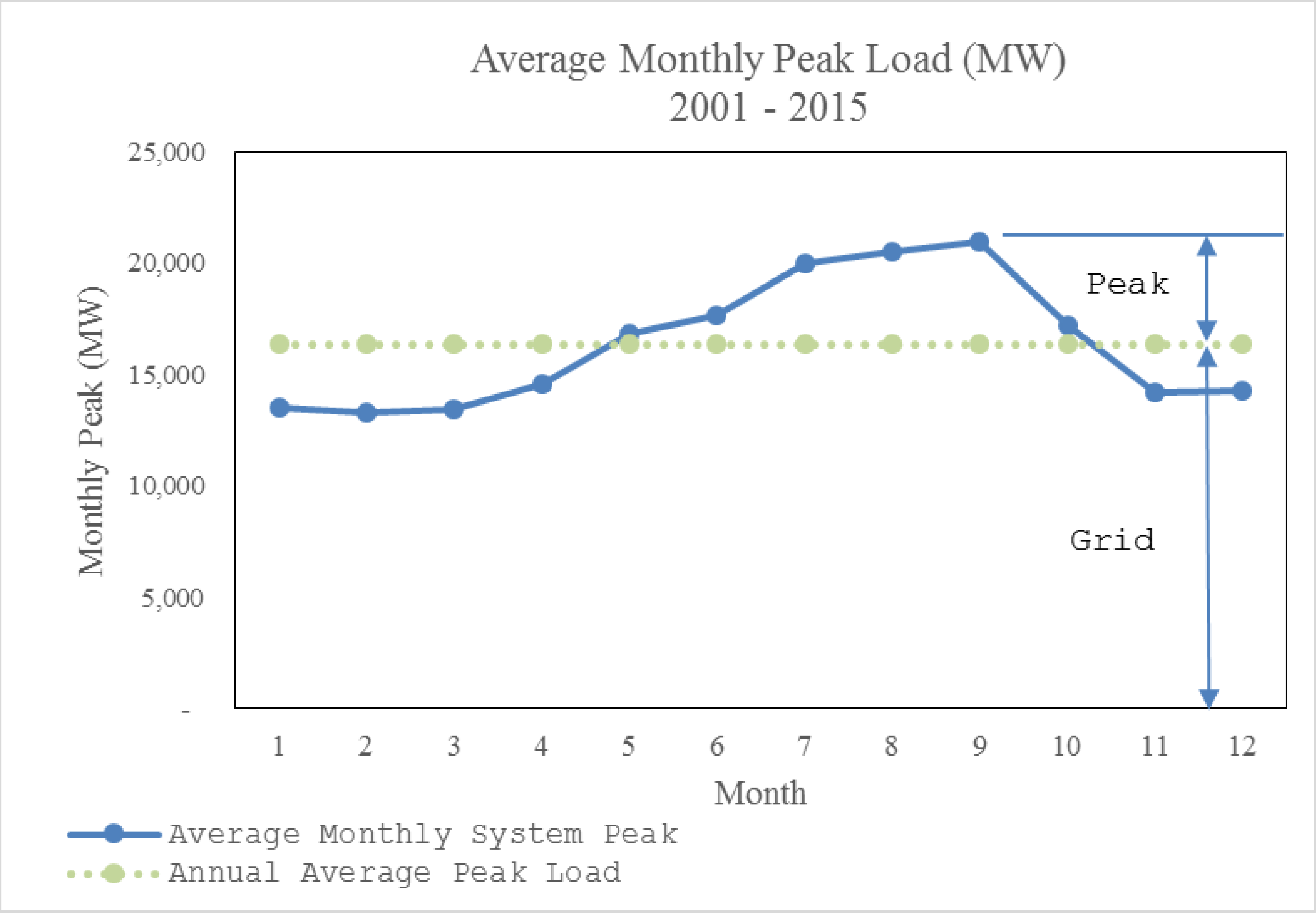
SCE's 2016 TOU Rate Design Window (A.16-07-003, Rebuttal Testimony)
Transmission Cost Drivers #2

Historical Trend of Transmission Revenue Requirement ($-Millions), SCE RPS (%) and SCE System Peak Load (MW)



SCE's 2016 TOU Rate Design Window (A.16-07-003, Rebuttal Testimony)
Transmission Cost Drivers #3

Bifurcation of Transmission System Marginal Costs Between Grid (70%) and Peak (30%) Based on Monthly Peak Load



SCE – 2018 GRC Phase 2 Appendix

Energy for What's Ahead℠

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2018 GRC Phase 2 – What's New…

Updated TOU Periods (based on 2016 RDW proposals)	Inclusion of Flexible Generation Capacity	Time-Differentiated Distribution	Customer Charge Modifications
• **Current**: Legacy TOU periods reflecting 12-6 pm summer weekday peak period • **Proposed**: Updated TOU periods reflecting impacts of RPS duck curve	• **Current**: Peak • **Proposed**: Peak + Flex	• **Current**: Use EDF methodology to allocate distribution design demand costs • **Proposed**: PLRF (Peak) + EDF (Grid) methodologies to allocate distribution design demand costs	• **Current**: Recovers none or a portion of FLT costs via $/mo customer charge with balance recovered via FRD charges • **Proposed**: Recover FLT costs via grid-portion of distribution charge (50 kVA and below; >20 kW)
• Later peak period (12-6pm → 4-9pm) • Weekends no longer 100% off-peak • New winter super-off-peak (SOP) period from 8am-4pm • Implementation of grandfathered rates for eligible solar customers	• Flex capacity needed to meet "duck curve" ramp • Distributes marginal generation capacity costs over more months / periods (including the winter season), instead of just the summer on-peak period	• Bifurcating distribution design demand costs between peak and grid, which is similar to generation energy and capacity split • Using peak load risk factor (PLRF) methodology to time-differentiate "peak" costs and EDF methodology to allocate grid costs • Allows for time-differentiated distribution rates	• Minimizes differences in customer charge when customers move between rate groups due to usage changes

Overview of Rate Design

- Revenue Requirements = authorized functional revenues that SCE used to establish rates in January 2017
- Sales Forecast = system usage for Bundled Service customers adjusted for departing load in 2018

C&I / A&P Rates

Two Basic Structures =

1. **Option D** (similar to existing Option B)
2. **Option E** (similar to existing Options A/R)

Differ in the recovery of generation peak capacity costs and distribution peak-related costs

- Option D recovers more via demand charges
- Option E recovers more via energy charges

Also proposing **grandfathered rate structures** with legacy TOU periods for eligible solar customers

Residential Rates

Default Tiered Rates

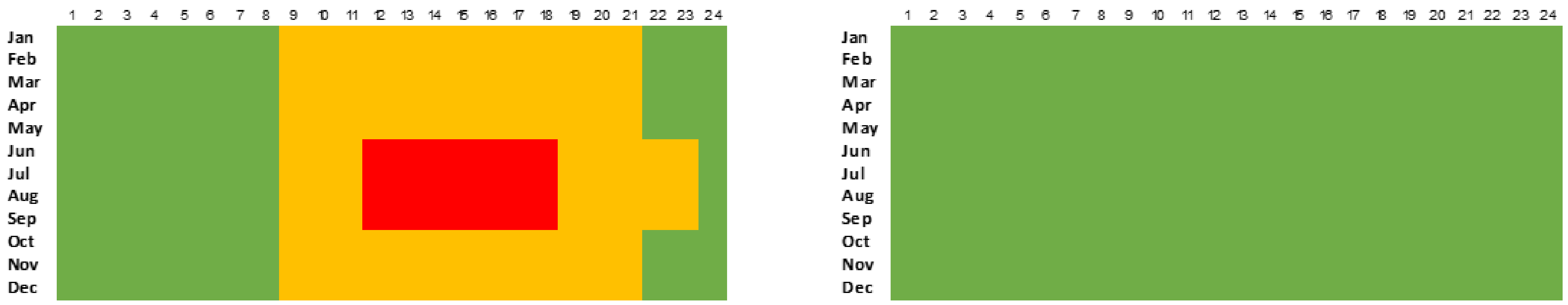
- Continue to recover almost all costs via volumetric, non-TOU energy charges
- Include small fixed and minimum charges (fixed charges will be addressed in SCE's December 2017 residential RDW application)
- Modifications pursuant to the provisions adopted in RROIR, with updated marginal cost and revenue allocations
- Seasonal rate differentials being addressed in December 2017 RDW

Optional TOU Rates

- Introducing time-differentiated distribution
- *Legacy TOU Periods*
  - TOU-D-T
  - TOU-D-A
  - TOU-D-B
  - TOU-EV-1
- *Updated TOU Periods*
  - Default Rate 1
  - Default Rate 2
  - TOU-D-C

Rate Design Forum –
- SCE's TOU Period Proposal

Weekdays **Existing** Weekends



Weekdays **Proposed** Weekends