California Energy Commission

Time of Use Rate Scenarios:
Inputs and Assumptions

2017 Integrated Energy Policy Report
California Energy Commission

DAWG, March 17, 2017

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Background on Residential TOU Activity

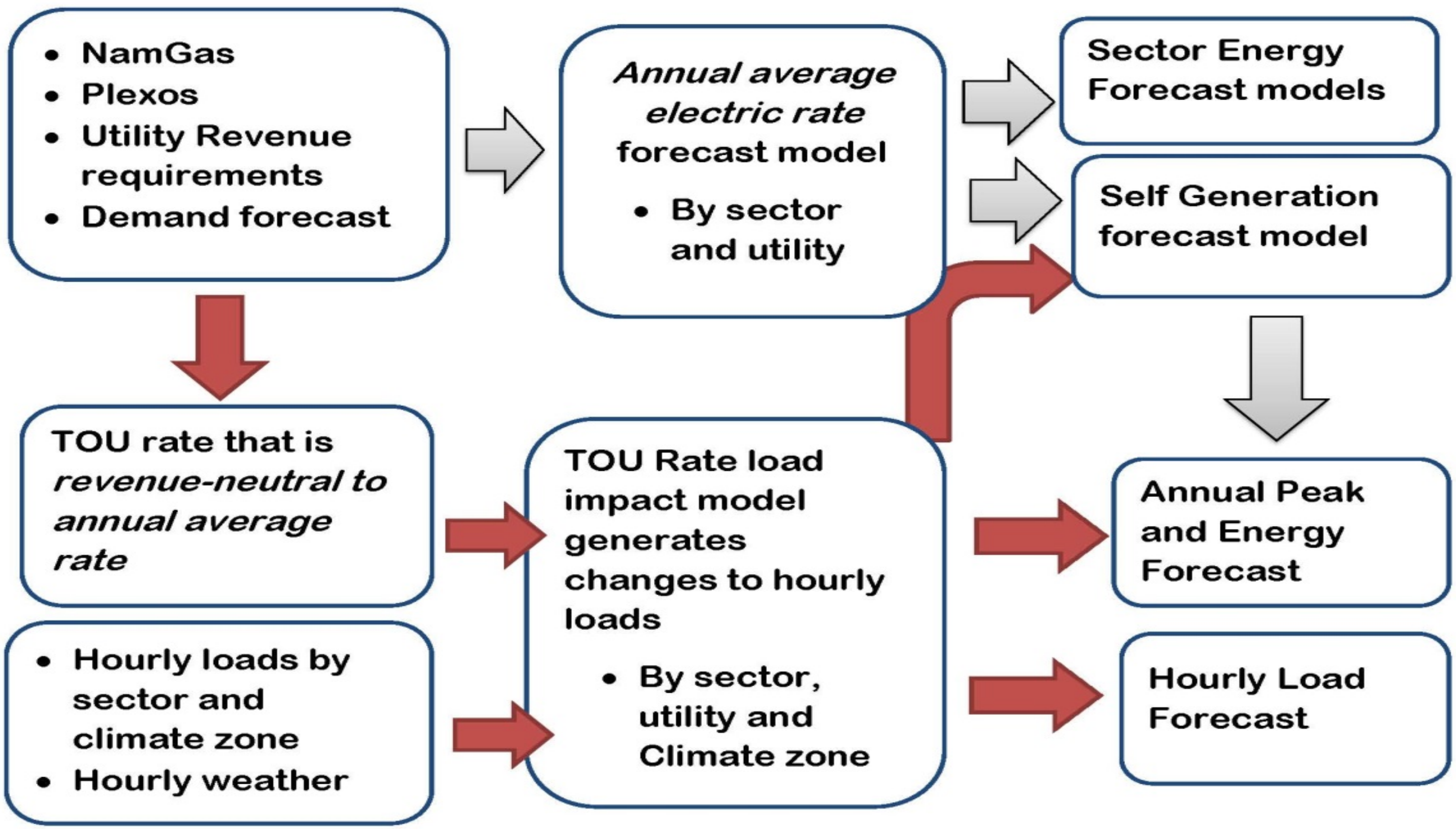
IOUs

- Opt-in pilot of various rate designs began summer 2016 and continues through 2017
- Default pilot begins 2018 (700,000 customers)
- Residential Default rollout in 2019
  - Decision on exempt customers in 2017
- Peak period shifting from late afternoon to early evening
  - Decisions on rate cases in 2017 for 2018 implementation

SMUD Board has committed to default TOU

- Staff will model on the IOU timeline for now.

Electric Rate Projections: Annual and Time-of-Use (TOU)



Nonresidential TOU Impacts

IOUs have been transitioning small/medium commercial and agriculture customers to time-varying rates for several years.

SDG&E and PG&E completed in 2016 and 2017.

SCE will simultaneously implement new TOU periods and default CPP for 500,000 accounts in late 2018.

- Most effects are embedded or will be in 2017
- Load impact studies for already-defaulted customers can be used to estimate the incremental impact of final migration and TOU period changes.

Modeling Incremental TOU impacts

1. Calculate elasticities by climate zone, season or month, and day-type. For example, the CES (constant elasticity of substitution) formulation has two components:
   - Peak/off-peak substitution elasticity accounts for load shifting from peak to off-peak (or super-off peak).
   - Daily price elasticity measures reduction in total usage in response to a higher average daily seasonal price relative to the flat rate (i.e., the rate used in the sector forecasts).
- TOU rate must be calculated to be revenue neutral to the average bundled rate in the planning area rate projections, to capture incremental price effects
- Estimated elasticities should reflect effects of projected temperatures and air conditioning saturations

Modeling Incremental TOU impacts (2)

2. Estimate number of participating customers
3. Aggregate hourly customer loads to TOU periods.
   – Load shapes should be adjusted for energy efficiency, distributed generation, and electrification
4. Apply elasticities to aggregated loads to produce load impact by TOU period, and apply percent change to adjusted hourly loads.

Elasticity Analysis Resources: Statewide Pricing Pilot (SPP) 2003-2004:

- A primary objective was to estimate the average impact of time-varying rates on energy use by rate period and develop models that can be used to predict impacts under alternative pricing plans
- All 3 IOUs, varied climate zones, 18 months
- Econometric estimation of a structural demand model with CES specification as a function of peak-to-offpeak temperature differential and AC saturation, by winter and inner/outer summer.
- Opt-in only, somewhat different TOU periods (2-7) ; relevant sample is a CPP rate (CPP-F); 2-period rate only

Staff has an initial model implemented using SPP model coefficients, but these reflect opt-in customers.

SPP Effective Elasticities

$ES = -\mathit{0.02726} - 0.0022(\mathit{CDH}_{peak} - \mathit{CDH}_{offpeak}) - 0.07096 * \text{AC Saturation}$

CDH = Average Cooling Degree Hours

- **Temperature differential will vary by seasonally by climate zone, with climate scenarios , length of peak period and specific hours in a given rate.**
- **Similar equation for winter**
- **But research has shown that price response does not always vary strictly proportional to price differential**

Elasticity Source Options (2)

SMUD SmartPricing Options Pilot (SPO) 2012-2013

- Summer only, both default and opt-in rates
- One-third of defaulted customers were unaware they were on the rate; default load impacts were about half of opt-in customers (9.4% v. 5.8%)
- SMUD only (90% air conditioning saturation)
  - Nexant work DR Potential study developed a statistical adjustment for other climate zones to produce elasticity as a function of AC saturations
  - Unawareness & complacency could vary by climate zone and utility

	Peak/OffPeak Elasticity	Daily Price Elasticity
SPO Pilot Default TOU	-0.056	-0.015
SPO Pilot Opt-in	-0.155	-0.028

Elasticity Source Options (3)

2016-2017 IOU Opt-in Pilot

- Evaluation results will include load impacts, but estimation of adjusted elasticities was not a study objective
- Opt-in but "pay to play" design to attract "complacents"
- Evening peak periods; some three period rates, including weekends

Evaluation of summer load impacts are available now but must be interpreted with caution; full year results available in Sept. 2017.

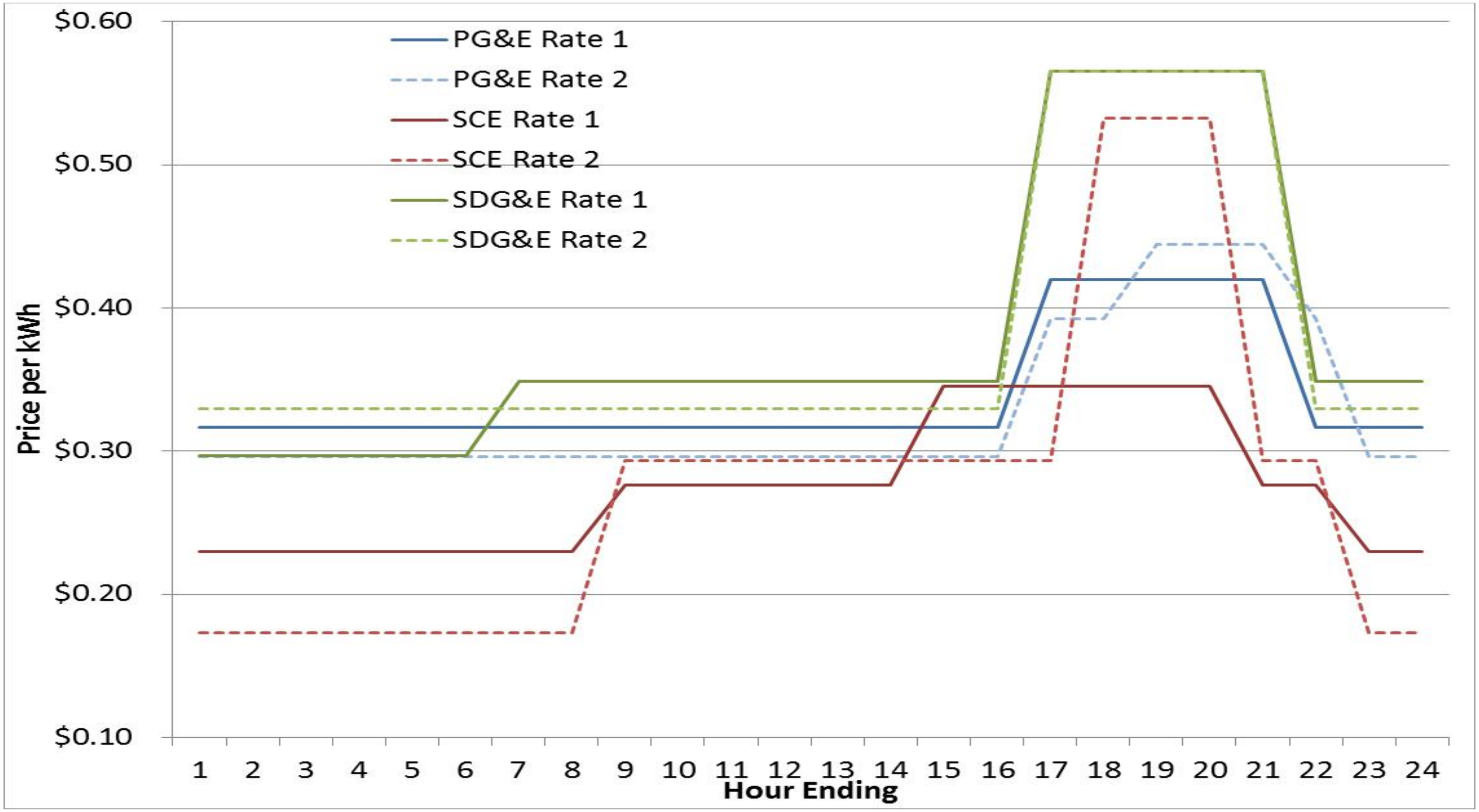
These results provide some insights and a point of comparison of staff load impacts, but research is ongoing; learnings will result in changes to communications, etc.

Comparison of Summer Weekday Elasticities

SPP Elasticities		
Statewide Climate Zones	Substitution	Daily
4. Hot	-0.122	-0.038
3. Moderate	-0.111	-0.029
2. Cool/Moderate	-0.065	-0.042
1.Cool	-0.039	-0.04

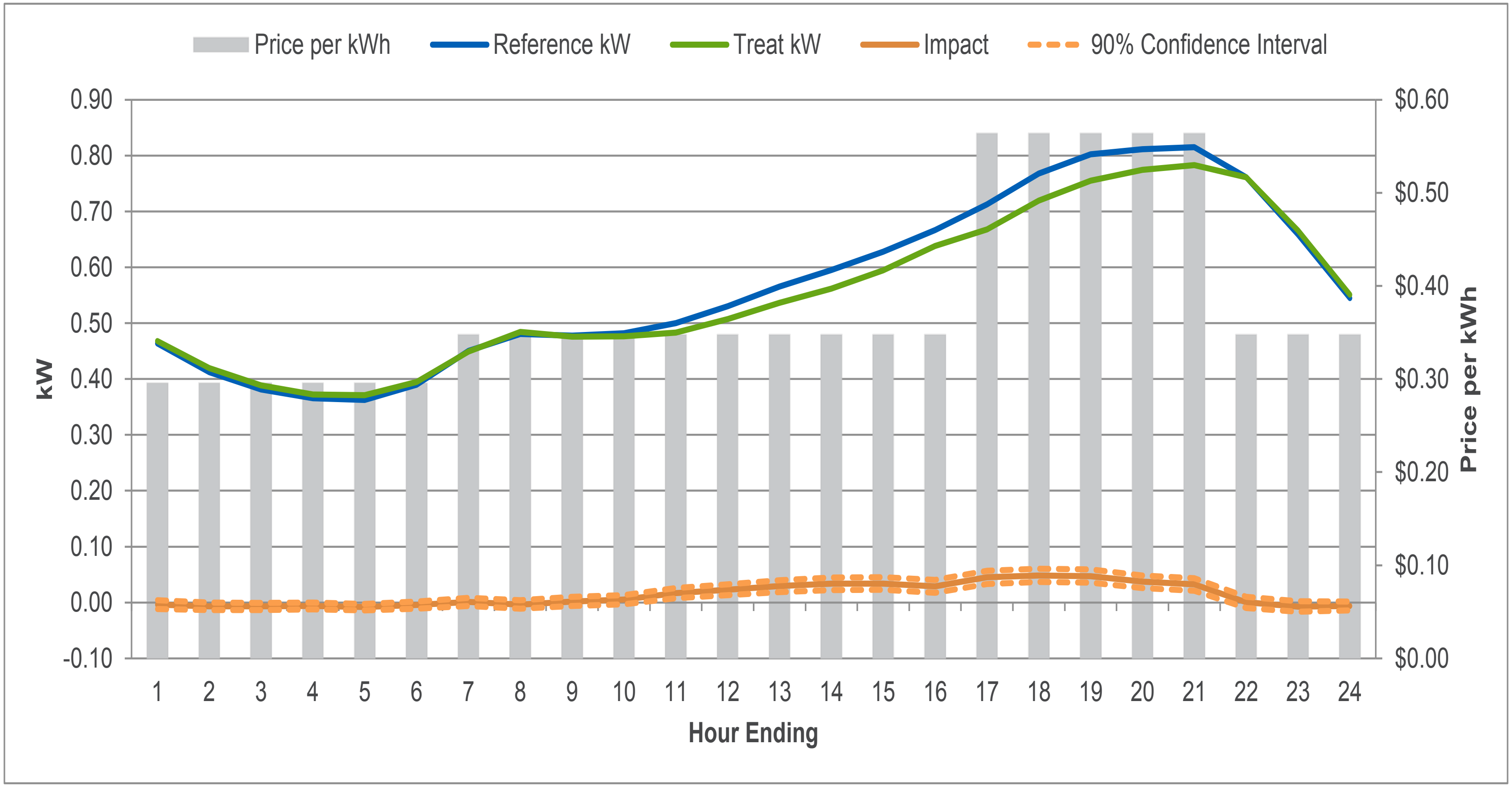
Staff Estimates using SPP Parameters and CEC 2013/14 Load and Temperature Data			
CEC Forecast Zone	Substitution	Daily	CAC Saturation 2016
13. SMUD	-0.133	-0.045	91%
11. SCE Eastern	-0.118	-0.044	85%
10. SCE Northeast	-0.118	-0.044	84%
5. PGE Southern Valley	-0.126	-0.039	82%
3. PGE North Valley	-0.121	-0.041	80%
9. SCE Big Creek East	-0.114	-0.036	75%
4. PGE Central Valley	-0.108	-0.045	73%
7. SCE LA Metro	-0.086	-0.045	56%
8. SCE Big Creek West	-0.080	-0.047	52%
12. SDGE	-0.072	-0.044	47%
2. PGE North Coast	-0.082	-0.040	45%
6. PGE Central Coast	-0.069	-0.045	44%
1. PGE Greater Bay Area	-0.058	-0.044	30%

Summer Weekday Opt-in Pilot Rate



- Rates do not include baseline credit

SDG&E Opt-in Pilot Rate 1



SDG&E Opt-in Rate 1 Load Impacts

Period	Reference kW	Treat kW	Impact	Percent Impact	90% Confidence Interval		CEC Staff Model
Peak	0.78	0.74	0.042	5.4%	0.037	0.047	5.2%
Off-Peak	0.56	0.55	0.01	2.1%	0.009	0.015	-1.2%
Super Off-Peak	0.40	0.40	-0.01	-1.6%	-0.009	-0.004	-4.9%
Daily kWh	13.63	13.30	0.33	2.4%	0.283	0.374	0.0%

- Rate 1 did not include any customers in “hot” climate zone
- Peak/Super off-peak ratio comparable to SPP
- Study population central AC saturation is 49% versus 47% staff estimate
- Off-peak/super off peak substitution coefficient appears not a good fit for this rate
- Weekend impacts were comparable to weekdays

PG&E Opt-in Rate 1 &2 Load Impacts

Rate 1	Study Results			CEC Staff Model		
	Peak	Offpeak	Daily	Peak	Offpeak	Daily
Hot	6.7%	0.0%	2.3%	4.2%	0.2%	1.5%
Moderate	4.6%	-0.7%	0.9%	3.4%	0.6%	1.4%
Cool	4.0%	-1.0%	0.0%	3.0%	1.0%	1.5%

Rate 2	Study Results				CEC Staff Model			
	Peak	Partial Peak	Offpeak	Daily	Peak	Partial Peak	Offpeak	Daily
Hot	6.8%	4.3%	-1.8%	1.1%	6.6%	5.3%	0.2%	2.4%
Moderate	5.8%	5.8%	-3.1%	-0.6%	5.4%	4.5%	0.9%	2.3%
Cool	3.9%	3.9%	-1.4%	0.0%	4.9%	4.1%	1.5%	2.5%

- Positive value = load reduction
- Observed peak impacts comparable despite greater rate differential in Rate 2

SCE Opt-in Rate 1 & 2 Load Impacts

Rate 1	Study Results				CEC Staff Model			
	Peak	Partial Peak	Offpeak	Daily	Peak	Partial Peak	Offpeak	Daily
Hot	1.3%	0.9%	-3.2%	-0.1%	4.1%	0.9%	-2.1%	1.3%
Modera	4.9%	3.7%	-1.5%	2.6%	3.3%	1.2%	-0.7%	1.3%
Cool	5.1%	2.6%	0.0%	2.6%	3.4%	1.1%	-1.0%	1.3%

Rate 2	Study Results				CEC Staff Model			
	Peak	Partial Peak	Offpeak	Daily	Peak	Partial Peak	Offpeak	Daily
Hot	3.1%	1.8%	-1.7%	1.0%	9.8%	3.7%	-6.8%	2.0%
Modera	4.5%	3.0%	-3.7%	1.4%	7.8%	3.2%	-3.4%	2.1%
Cool	4.3%	2.3%	0.0%	1.9%	7.8%	3.2%	-4.1%	2.0%

- Similar observed impacts despite higher differential in Rate 2 while staff model estimates much higher impacts

Key Rate Design Assumptions

- Peak to off peak rate differential
  - CPUC Resolutions on default pilot rates should indicate likely starting point.
  - After 2019 ,"The shift toward more fully cost-based price differentials may be made later, informed by data and experience …." (CPUC D.15-07-001)
- Number participating=total households – exempt - opt-out
  - CPUC Decision in 2017 on exempt customers
- Accounting for unawareness-adjust elasticities and/or participants?
- Fixed charges may be allowed in 2020, reducing volumetric rates.

Rate Scenarios

Mid Energy Demand Case:

- Mid demand, natural gas, and carbon prices
- Capital expenditure consistent with existing infrastructure plans, and customer and peak forecast

High Energy Demand Case (Low Rates)

- Low natural gas and carbon prices
- More sales to recover transmission and distribution and other relatively fixed costs
- Less investment in infrastructure

Low Energy Demand Case (High Rates)

- High natural gas and carbon prices
- Lower demand means fixed costs per kwh of sales are higher
- More investment to support distributed resources

TOU Scenarios

- Mid Case
  - Gradual increase in peak-to-off peak rate differential from 2018 pilot rates, although SDG&E's are already higher
  - Moderate opt-out/unawareness adjustment (proportionate to SMUD?)
- Low Demand/High Rates/High Engagement
  - Fixed charge (or time-differentiated distribution charges) enables a lower off-peak rate, higher differential
  - more engagement (higher substitution elasticity)
- High Demand/Low Rates/Low Engagement
  - Maintain differential at starting point
  - Larger reduction to elasticities or enrollment

Schedule

- August. 3rd workshop – preliminary results
- August/Sept. –Revise impacts to include CPUC decisions and consider full-year survey research and load impact results
- October – DAWG to revisit scenarios and assumptions
- November – revised load impacts