San Diego Gas & Electric GRC Phase 2 Workshop

February 22, 2016



Witness Team

- **Chapter 1:** *Cynthia Fang* – Rate Design Policy Objectives
- **Chapter 2:** *Chris Swartz* – Rate Design and Revenue Allocations
- **Chapter 3:** *Rob Anderson* – Support for Updated TOU Periods
- **Chapter 4:** *Ken Schiermeyer* – Updated Sales Forecast, including proposal for annual update
- **Chapter 5:** *John Baranowski* – Support for Non-Coincident Demand Charge
- **Chapter 6:** *William Saxe* – Updated Distribution Marginal Cost Studies and Allocations
- **Chapter 7:** *Jeff Shaughnessy* – Updated Commodity Marginal Cost Studies and Allocations
- **Chapter 8:** *Jennifer Reynolds*– Proposal for Schedule A Compliance, Stakeholder Outreach efforts and ME&O Plan
- **Chapter 9:** *Leslie Willoughby* – Updated CPP Trigger Threshold

Ch. 1: Policy
Rate Design Policy Objectives

Ch.1: Policy
Current Standard Rate Structures

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Residential	Small Commercial	Medium and Large Commercial and Industrial (“M/L C&I”)	Agricultural	Streetlighting
• Fully bundled energy rate • Currently 3-tiered and differs by season • Recovers all costs (rate components) through energy rates	• Partially unbundled • Reduced monthly service fee for partial recovery of customer-related distribution costs that varies by demand • Remaining costs recovered through energy rates, differs by season and TOU period	• Unbundled • Distribution costs recovered through a monthly service fee and demand charge • Transmission costs recovered through demand charges • Commodity costs recovered through peak demand charge and TOU energy rates • Remaining costs recovered through energy rates	• Partially unbundled • Reduced monthly service fee for partial recovery of customer-related distribution costs that varies by demand • Remaining costs recovered through energy rates that differ by season and TOU period • Optional rate with unbundled structure like M/L C&I	• Billed monthly on a per lamp basis

Ch. 1: Policy
Cost-Based Rate Structure

DISTRIBUTION

Customer Cost

$/Month

Customer Costs:

SDG&E incurs these costs on a fixed basis for each interconnected customer whether or not the customer uses electricity

Distribution Demand

$/NCD-kW

Distribution Demand Costs:

SDG&E incurs on a fixed cost basis to meet the combined maximum demand of customers served off of a circuit to ensure ability to deliver reliable grid services

COMMODITY

Generation Capacity

$/Peak kW

Generation Capacity Costs:

SDG&E incurs these costs on a fixed basis based upon the peak demand of the system to ensure reliable service to customers on those peak days

Time-of-Use Energy

$/kWh (TOU)

Energy Costs:

SDG&E incurs these costs on a variable basis depending on the time of delivery to meet customers energy usage

Ch. 1: Policy
Rate Design Proposals

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Continue Movement toward Cost Based Rates & Transparent Incentives

Monthly Service Fee	Distribution Demand Charges	Commodity Demand Charges	Public Purpose Programs
Gradual multi-year increases MSF to better reflect customer-related fixed costs (Begins Year 1)	Transition the recovery of distribution demand costs to 100% non-coincident demand (NCD) with a super off-peak exemption (Begins Year 2)	Transition the recovery of generation capacity costs towards 100% demand charge (Begins Year 2)	Transition the recovery of CSI and SGIP cost from Distribution to PPP (Begins Year 1)
All Business	M&L C&I	M&L C&I	All Customers

Ch. 1: Policy

TOU Period Proposal

	TOU Period	Current Standard TOU	2015 RDW Proposal	2016 GRC P2 Proposal
Summer	On-Peak	11 a.m.-6 p.m. weekdays	2-9 p.m. weekdays	Shorten to 5 hours (4-9 p.m. daily)
	Semi-Peak	6-11 a.m. and 6-10 p.m. weekdays	All other hours	-
	Off-Peak	All other hours, weekends/holidays	-	All other hours
	Super Off-Peak	-	12-6 a.m. daily	Expanded Weekend Hours (12 a.m.-2 p.m. weekends/holidays, 12-6 a.m. weekdays)
Winter	On-Peak	5-8 p.m. weekdays	5-9 p.m. weekdays	Simplified - same as summer
	Semi-Peak	6 a.m.-5 p.m. and 8-10 p.m. weekdays	All other hours	
	Off-Peak	All other hours, weekends/holidays	-	
	Super Off-Peak	-	12-6 a.m. daily	
	CPP Period	11 a.m.-6 p.m. year round	2-6 p.m. year round	Shorten CPP Period to 4 hours (2-6 p.m. year round)

Ch. 1: Policy
Distribution Rate Cost Structure

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Distribution Customer Costs	Distribution Demand Costs
Costs of ensuring customers are ready to receive service ("curb to meter" services) • Cost of meter – Measure customer energy and load • Cost of service lines – Connect individual customers to their service transformer • Cost of final transformer – Steps down voltage to usable, safe levels • Cost of customer services – Customer service field, advanced metering, billing, credit and collections, branch offices, customer contact center, residential customer services, commercial and industrial services, communications, customer programs, etc.	• Feeders and Local Distribution – Costs associated with primary distribution system – Switches, conductors, capacitors, line regulators, insulators, poles, vaults, conduit, fuses, etc. • Substation – Costs associated with the point of conversion from transmission to distribution voltages – Transformers, circuit breakers, switches, insulators, bus work, control houses, system protection, etc.

Ch. 1: Policy
Food Bank Proposal

- Proposed pursuant to Public Utilities Code Section 739.3, added by AB2218
- 20% line item discount
- Available to customers classified as “food banks” using the NAICS
- Recovered from all non-CARE customers, through PPP rates, consistent with the existing CARE discount

Ch. 2: Revenue Allocations
Distribution Revenue Allocation

- SDG&E proposes to update distribution revenue allocations to reflect updated sales determinants and distribution marginal cost studies (Ch. 6 – Saxe).

- Due to the resulting changes in distribution revenue allocations, SDG&E proposes a three-year phase in.

Distribution Revenue Allocation Proposal (Three-Year Transition)

	Current (%)	Year 1 (%)	Year 2 (%)	Year 3 (%)	% Change Comparing Year 3 to Current
Residential	47.61%	49.81%	52.00%	54.19%	13.83%
Small Commercial	12.68%	13.25%	13.81%	14.37%	13.32%
M/L C&I	37.68%	35.03%	32.38%	29.74%	-21.09%
Agricultural	1.33%	1.24%	1.15%	1.05%	-21.18%
Streetlighting	0.69%	0.68%	0.66%	0.65%	-6.22%
System	**100%**	**100%**	**100%**	**100%**	**0.00%**

Ch. 2: Revenue Allocations

Commodity Revenue Allocations

- SDG&E proposes to update commodity revenue allocations to reflect updated sales determinants and commodity marginal cost studies (Ch. 7 – Shaughnessy).
- Due to the resulting changes in commodity revenue allocations, SDG&E proposes a three-year phase in.

Commodity Revenue Allocation Proposal (Three-Year Transition)

	Current (%)	Year 1 (%)	Year 2 (%)	Year 3 (%)	% Change Comparing Year 3 to Current
Residential	45.69%	46.70%	47.70%	48.71%	6.61%
Small Commercial	11.34%	11.50%	11.66%	11.83%	4.34%
M/L C&I	41.02%	39.79%	38.56%	37.33%	-8.99%
Agricultural	1.53%	1.57%	1.60%	1.64%	7.23%
Streetlighting	0.42%	0.44%	0.47%	0.49%	14.71%
System	**100%**	**100%**	**100%**	**100%**	**0.00%**

Ch. 2: Revenue Allocations
PPP Revenue Allocation

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- SDG&E proposes to update PPP revenue allocations to reflect updated sales determinants and the movement of Schedule PA-T-1 to the Agricultural customer class.
- While SDG&E is not proposing to change the revenue allocations for SGIP and CSI, SDG&E proposes to move the recovery of the costs of these two programs from distribution rates to PPP rates.

Public Purpose Programs ("PPP") Revenue Allocation Proposal

	CARE		ESAP		Energy Efficiency		EPIC		Total PPP*	
	Current (%)	Proposed (%)	Current (%)	Proposed (%)	Current (%)	Proposed (%)	Current (%)	Proposed (%)	Current (%)	Proposed (%)
Residential	34.22%	34.27%	37.68%	38.38%	34.52%	36.28%	41.30%	38.21%	35.71%	36.43%
Small Commercial	10.69%	10.79%	10.12%	10.11%	15.13%	14.57%	14.00%	10.06%	12.06%	11.81%
M/L C&I	54.61%	53.18%	51.75%	49.85%	49.28%	47.47%	43.50%	49.62%	51.51%	50.37%
Agricultural	0.48%	1.77%	0.45%	1.65%	0.60%	1.29%	0.50%	1.64%	0.50%	1.21%
Streetlighting	0.00%	0.00%	0.00%	0.00%	0.47%	0.38%	0.70%	0.46%	0.22%	0.17%
System	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

*The Total PPP allocations presented do not include SGIP and CSI allocations since they are not changing

Ch. 2: Revenue Allocations
CTC Revenue Allocations

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- SDG&E proposes to update Competition Transition Charge (CTC) revenue allocations to reflect updated sales determinants and updated Top 100 hours (Ch. 7 – Shaughnessy).

Competition Transition Charge ("CTC") Revenue Allocation Proposal

	Current (%)	Proposed (%)	Percentage Change (%)
Residential	40.89%	40.79%	-0.24%
Small Commercial	11.61%	11.29%	-2.81%
M/L C&I	46.48%	46.80%	0.70%
Agricultural	1.02%	1.10%	7.94%
Streetlighting	0.00%	0.02%	N/A
System	100%	100%	0.00%

Ch. 2: Revenue Allocations
LGC Revenue Allocations

- SDG&E proposes to update Local Generation Charge (LGC) revenue allocations to reflect the updated 12-month coincident peak (FERC Docket No. ER15-553-000).

Local Generation Charge ("LGC") Revenue Allocation Proposal

	Current (%)	Proposed (%)	Percentage Change (%)
Residential	40.84%	40.89%	0.13%
Small Commercial	11.46%	11.03%	-3.73%
M/L C&I	47.31%	46.81%	-1.06%
Agricultural	0.00%	0.89%	N/A
Streetlighting	0.39%	0.38%	-3.37%
System	**100%**	**100%**	**0.00%**

Ch. 2: Revenue Allocations
Summary by Rate Component

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Percent Change of Revenue Allocations by Component

	Distribution (In Year 3)	Commodity (In Year 3)	PPP	CTC	LGC
Residential	13.83%	6.61%	2.03%	-0.24%	0.13%
Small Commercial	13.32%	4.34%	-2.06%	-2.81%	-3.73%
M/L C&I	-21.09%	-8.99%	-2.22%	0.70%	-1.06%
Agricultural	-21.18%	7.23%	144.48%	7.94%	N/A
Streetlighting	-6.22%	14.71%	-21.08%	N/A	-3.37%
Component as Percentage of Total Revenues	34%	46%	7%	<1%	<1%

Ch. 2: Revenue Allocations
Summary of Total Allocations by Year

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Summary of Illustrative Total Revenue Allocations (Incremental)

	Current	Year 1	% Change from Current to Year 1	Year 2	% Change from Year 1 to Year 2	Year 3	% Change from Year 2 to Year 3
Residential	43.73%	45.32%	3.64%	46.54%	2.69%	47.76%	2.62%
Small Commercial	12.01%	12.23%	1.86%	12.50%	2.22%	12.78%	2.17%
M/L C&I	42.37%	40.57%	-4.25%	39.09%	-3.64%	37.62%	-3.78%
Agricultural	1.38%	1.37%	-1.21%	1.35%	-1.20%	1.33%	-1.21%
Streetlighting	0.51%	0.51%	-0.25%	0.51%	0.90%	0.52%	0.89%

Ch. 2: Movement Towards Cost Based Rates

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Summary of Changes for Small Commercial (Schedule A/ TOU-A)

	Current	Year 1	Year 2	Year 3
Customer Costs	MSF based on demand with residual in energy rate	Increase MSF based on demand and decrease residual in energy rate	Increase MSF based on demand and decrease residual in energy rate	Increase (double current) MSF based on demand and decrease residual in energy rate
Distribution Demand	Energy rate	Energy rate	Energy rate	Energy rate
Generation Capacity	Flat energy (mandatory transition to TOU)	TOU energy	TOU energy-- increased differential	TOU energy-- increased differential
Commodity Energy	Flat energy (mandatory transition to TOU)	TOU energy	TOU energy-- increased differential	TOU energy-- increased differential

Ch. 2: Movement Towards Cost Based Rates

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Summary of Changes for M/L C&I (Schedule AL-TOU)

	Current	Year 1	Year 2	Year 3
Customer Costs	MSF with residual in demand charges	Increase MSF 20% with decrease residual in demand charges	Increase MSF 20% with decrease residual in demand charges	Increase MSF 20% with decrease residual in demand charges
Distribution Demand	65% NCD/35% Peak	No change from current (65% NCD/35% Peak)	75% NCD/25% Peak	85% NCD/15% Peak
Generation Capacity	50% on-peak demand charge with residual in energy rate	No change from current (50% on-peak demand charge with residual in energy rate)	60% on-peak demand charge with reduced residual in energy rate	70% on-peak demand charge with reduced residual in energy rate
Commodity Energy	TOU energy	TOU energy	TOU energy	TOU energy

Ch. 2: Movement Towards Cost Based Rates

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Summary of Changes for Small Agricultural (Schedule PA <20kW)

	Current	Year 1	Year 2	Year 3
Customer Costs	MSF with residual in energy rate	20% Increase MSF and decrease residual in energy rate	20% Increase MSF and decrease residual in energy rate	20% Increase MSF and decrease residual in energy rate
Distribution Demand	Energy rate	Energy rate	Energy rate	Energy rate
Generation Capacity	Flat energy (mandatory transition to TOU)	TOU energy	TOU energy-- increased differential	TOU energy-- increased differential
Commodity Energy	Flat energy (mandatory transition to TOU)	TOU energy	TOU energy-- increased differential	TOU energy-- increased differential

Ch. 2: Movement Towards Cost Based Rates

Summary of Changes for M/L Agricultural (Schedule PA ≥ 20 kW)

	Current	Year 1	Year 2	Year 3
Customer Costs	MSF with residual in energy rate	20% Increase MSF and decrease residual in energy rate	20% Increase MSF and decrease residual in energy rate	20% Increase MSF and decrease residual in energy rate
Distribution Demand	Energy rate	Energy rate	Introduction of NCD at 20% and decrease residual in energy rate	Increase of NCD to 30% and decrease residual in energy rate
Generation Capacity	20% on-peak demand charge with residual in energy rate	20% on-peak demand charge with residual in energy rate	30% on-peak demand charge with reduced residual in energy rate	40% on-peak demand charge with reduced residual in energy rate
Commodity Energy	TOU energy	TOU energy	TOU energy	TOU energy

Ch. 2: Movement Towards Cost Based Rates

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- As SDG&E is proposing to have consistent TOU periods across all of its schedules, SDG&E is proposing to eliminate the different on-peak demand time options for PAT-1.

Summary of Changes for M/L Agricultural (Schedule PA-T-1)

	Current	Year 1	Year 2	Year 3
Customer Costs	MSF with residual in demand charges	Increase MSF 20% with decrease residual in demand charges	Increase MSF 20% with decrease residual in demand charges	Increase MSF 20% with decrease residual in demand charges
Distribution Demand	100% NCD with off-peak exemption	100% NCD with off-peak* exemption	100% NCD with off-peak* exemption	100% NCD with off-peak* exemption
Generation Capacity	50% on-peak demand charge with residual in energy rate	50% on-peak demand charge with residual in energy rate	60% on-peak demand charge with reduced residual in energy rate	70% on-peak demand charge with reduced residual in energy rate
Commodity Energy	TOU energy	TOU energy	TOU energy	TOU energy

*Under SDG&E's proposal, the exemption for PA-T-1 customers will be for the super off-peak period

Ch. 2: Movement Towards Cost Based Rates

- SDG&E is not proposing changes to residential tiered rate design in this proceeding
- Residential proposed rates and illustrative bill impacts reflect compliance with D.15-07-001
  - Tier consolidation glidepath
  - Baseline allowance reduction glidepath
  - Residential CARE average effective discount glidepath
  - Minimum bill changes

Ch. 2: Elimination of Rate Schedules

- SDG&E is proposing to eliminate four outdated rate schedules
  - M/L C&I Schedules "AD" and "AY-TOU"
    - Schedule "AD" has been closed since 1987; "AY-TOU" since 1999
    - Outdated and are no longer consistent with SDG&E's policy objectives
  - Schedules "A" and "PA"
    - Legacy flat rate option
    - Customers transitioning to mandatory TOU beginning November 2015
    - No customers will be on these rate schedules after April 2016

Ch. 2: New Customer Options

- New options for customers who are looking for more bill stability and less volatility
- Residential EV:
  - More cost-based option for residential EV customers that includes a monthly service fee and a rate design to further incent charging in the super off-peak period
  - Similar to SCE's TOU-D (Option B)
- Small Commercial:
  - An option consisting of a larger fixed charge and reduced volumetric rate, providing bill stability for small business customers that have less flexibility to change their energy use
  - An option that refreshes SDG&E's "A-TOU" schedule and introduces small commercial customers (w/ demand less than 40kW) to demand charges
- M/L C&I:
  - An fully cost-based option that includes: (1) cost-based MSF; (2) distribution demand charges recovered through a NCD charge with exemption for demand in super-off peak period; (3) on-peak demand charge reflecting 90% of generation capacity
  - This option could benefit C&I customers that have flexibility to shift energy use to SDG&E's super off-peak period

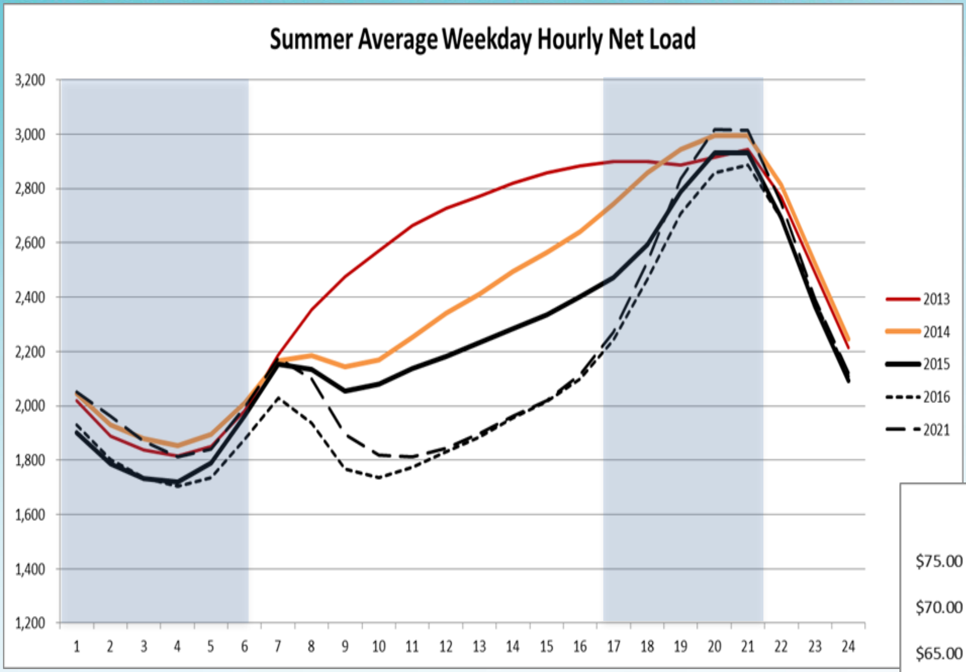
Ch. 2: Other Rate Design Proposals

- Reduction in PTR Incentives
  - Incentive is no longer needed with the implementation of the residential Smart Pricing Program (SPP) rates
  - SDG&E proposes a three-year glidepath to eliminate the PTR incentive
    - Year 1 - $0.50 / $1.00 per kWh
    - Year 2 - $0.25 / $0.50 per kWh
    - Year 3 – Incentive is eliminated
- Elimination of Under/Over-Collection Tracking Requirement
  - SDG&E requests authority to handle any revenue under/over collections resulting from these dynamic pricing rates/programs as any other revenue under/over collection, through SDG&E’s balancing accounts
- Compliance requirement to present Schedule A-TC as a separate class

Ch. 2: Streetlighting Updates

- Updates to Lighting Cost Studies
  - Proposed rates are reflected in Attachments D, F and H
- Framework for New Dimmable Rate Option
  - Supports need for an adaptive controls rate
  - SDG&E will continue to work with the parties to solicit feedback and support on this new rate option
- Class of Service for Schedule LS-1
  - SDG&E proposes to close LS-1 Class C rates to new customers
  - Existing LS-1 Class C customers will have the option to move to LS-1 Class B
- Removal of Obsolete Light (LS-1 - Mercury Vapor, 400W, Class C)

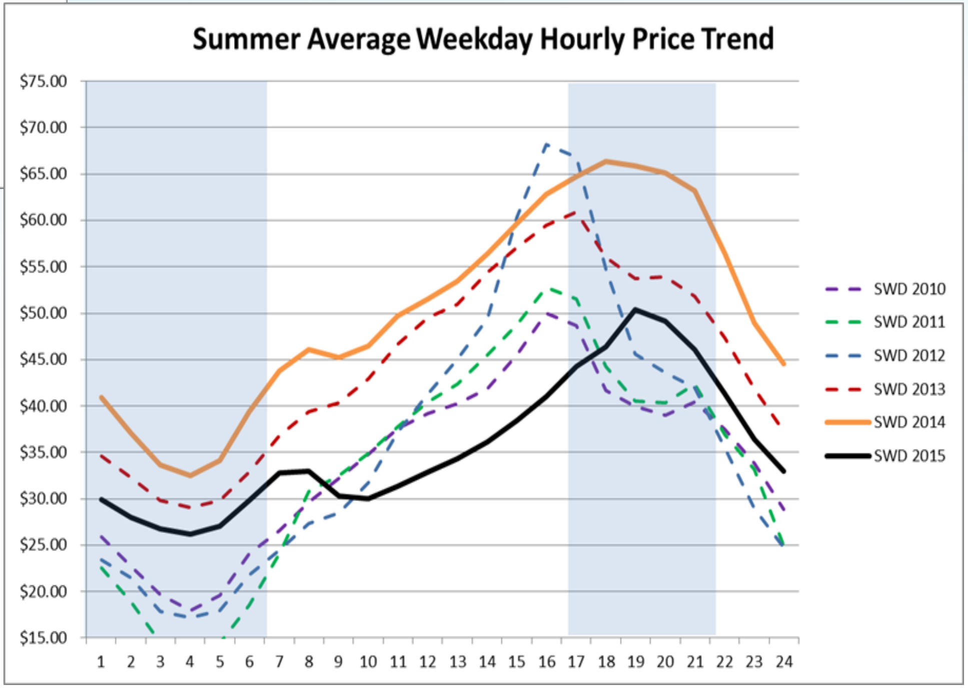
Ch. 3: Support for Updated TOU Periods
Summer TOU Proposal



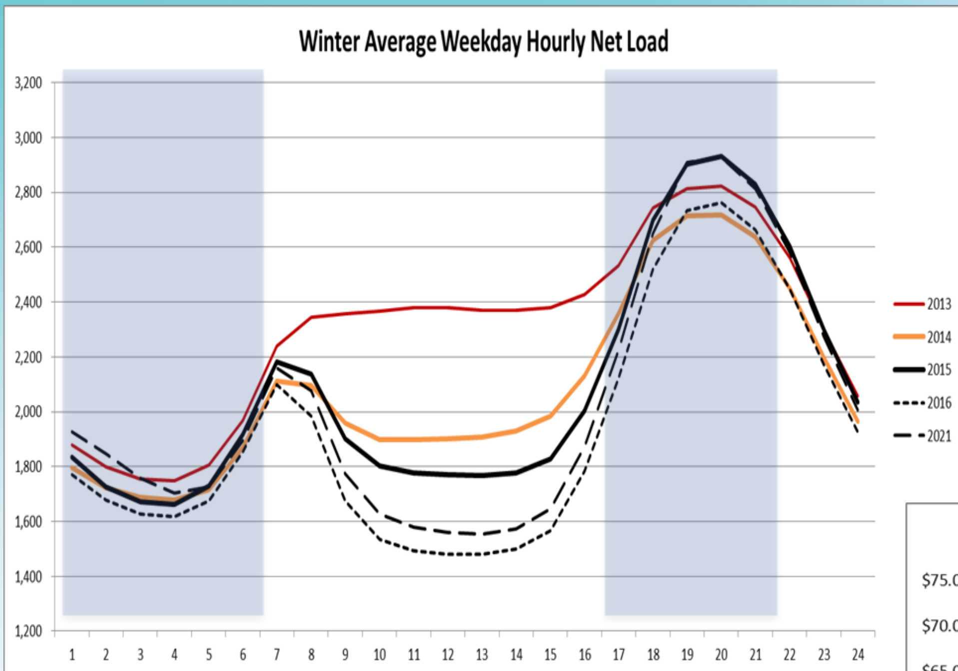
SDG&E is Relying on 2014 and 2015 Data for its Summer Weekday TOU Proposal

Highest prices and largest net loads are shifted to later in the day

Price levels vary year-to-year based on changing natural gas prices

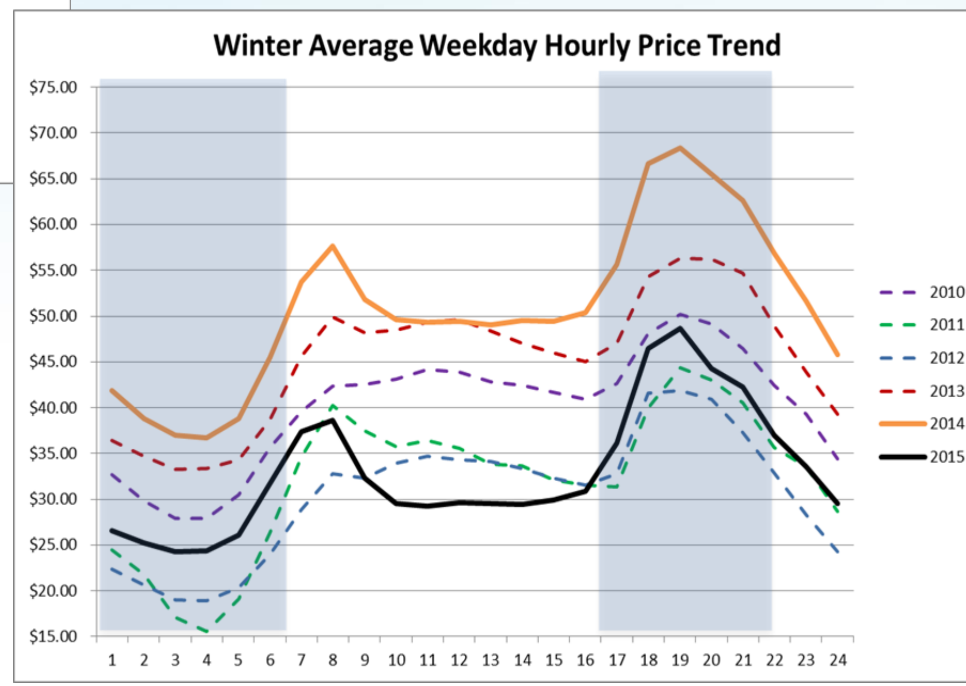


Ch. 3: Support for Updated TOU Periods
Winter TOU Proposal



SDG&E is Relying on 2014 and 2015 Data For Its Winter Weekday TOU Proposal

- The proposed TOU periods would capture the hours with the highest net load and highest contiguous electricity prices



Price levels vary year-to-year based on changing natural gas prices

Ch. 3: Support for Updated TOU Periods

Weekend TOU Proposal

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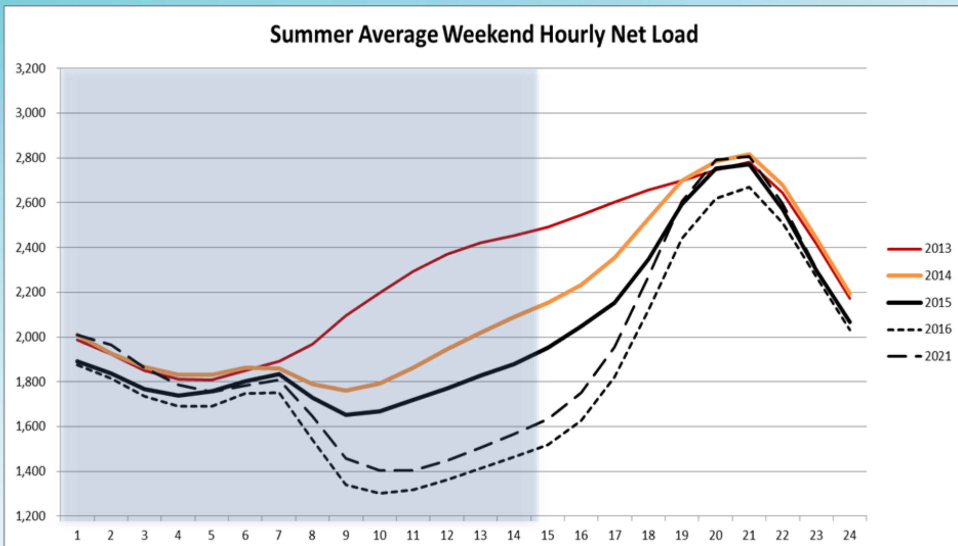
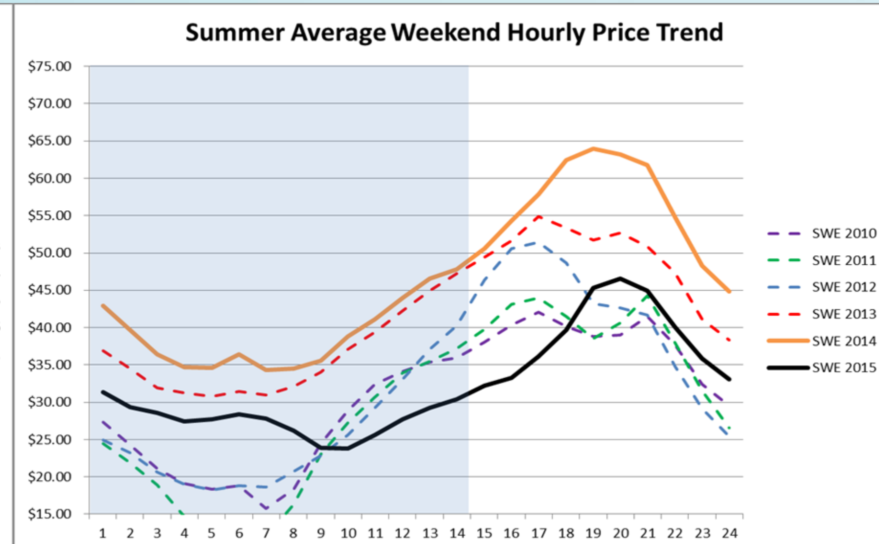
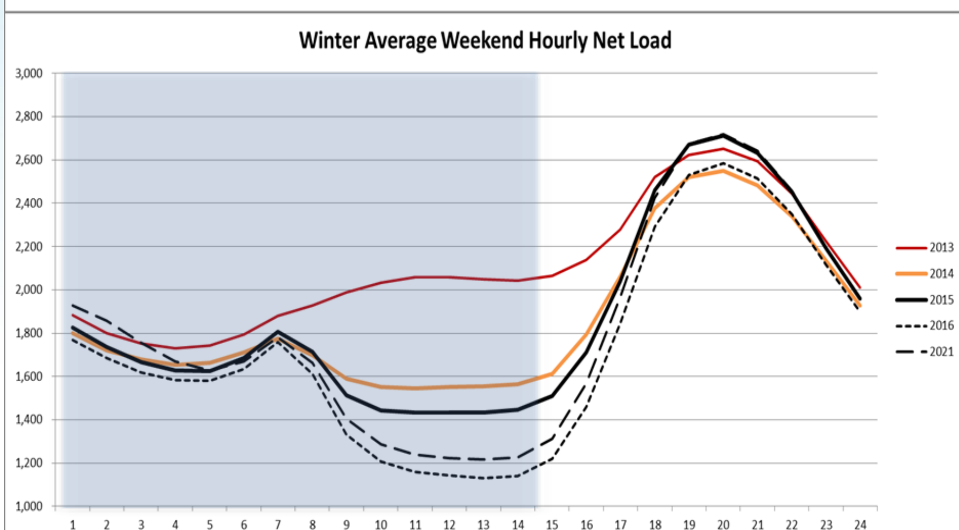
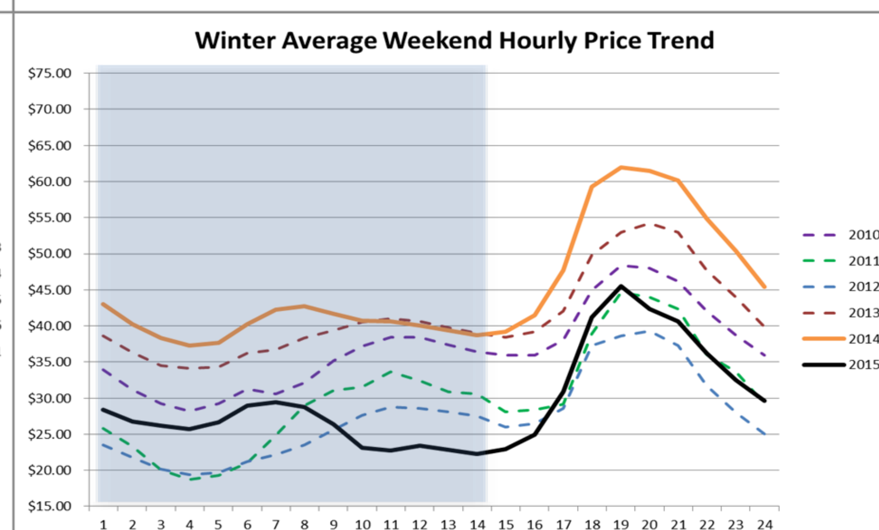
Weekends Have Little Morning Ramp and Prices through 2 pm are Comparable to Weekday 12 am – 6 am in 2014 and 2015





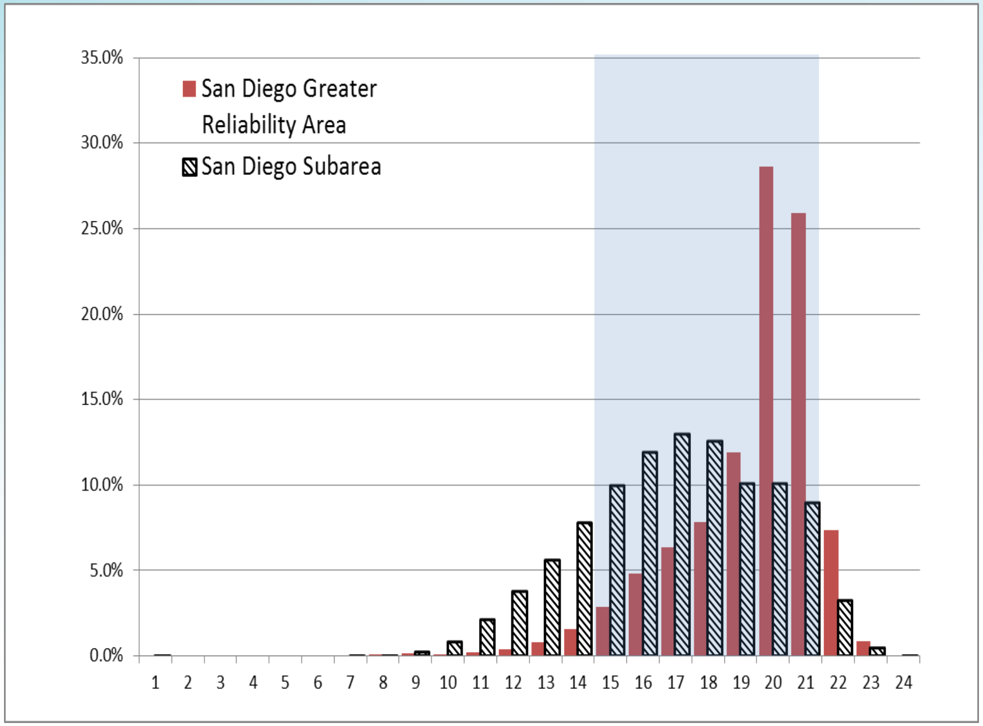




Ch. 3: Support for Updated TOU Periods
CPP Event Period

Relative Loss of Load Expectation shows local capacity needs during the 2-9pm on-peak period.

Relative Loss of Load Expectation for the San Diego Local Capacity Areas by Hour in the Summer



SDG&E proposes to address 2-9pm LOLE need through:

- A 2-6 pm CPP event period to address San Diego sub-area capacity needs
- A 4-9 pm on-peak TOU period to address greater San Diego Reliability Area capacity needs and the daily ramping needs

Ch. 4: Sales Forecast

TY 2016 Sales

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Forecast of TY 2016 Electric Sales

- Consistent with direction set forth in in Decision ("D.") 15-08-040, SDG&E is submitting an updated 2016 TY electric sales forecast as part of this testimony in support of its proposal to change its time of use ("TOU") periods.
- Both electric sales forecasts presented in TY 2016 GRC Phase 1 and TY 2016 GRC Phase 2 are based on a California Energy Commission's ("CEC") adopted California Energy Demand ("CED") forecast.
  - Phase 1 is based on the 2013 CED forecast
  - Phase 2 is based on the 2014 CED forecast

Comparison of Annual Electric Sales (GWh)				
Sector	GRC Phase 1 TY 2016	GRC Phase 2 TY 2016	Change	% Change
Residential	7,681	7,378	-303	-3.9%
Non-Residential	12,332	12,302	-30	-0.2%
Total	20,013	19,680	-333	-1.7%

Ch. 4: Sales Forecast

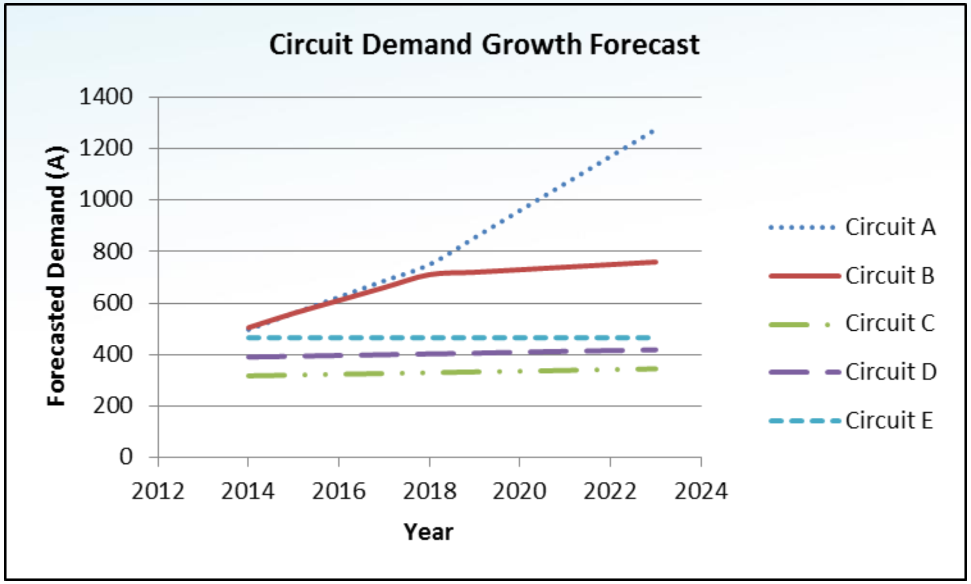
Proposal for Annual Update to TY Sales

- SDG&E proposes that the Commission approve the use of an annual advice letter to update SDG&E's electric sales forecast, beyond the test-year.
- Updates to the test year sales more frequently would better capture the changes in electric sales.
- This would noticeably reduce the impact of under/over collections related to differences between actual sales and test-year sales.
- Total sales are forecasted on the same basis as the TY 2016 sales forecast

Forecast of Electric Sales (GWh)			
	TY2016	TY2017	TY2018
Total Sales	19,680	19,616	19,559

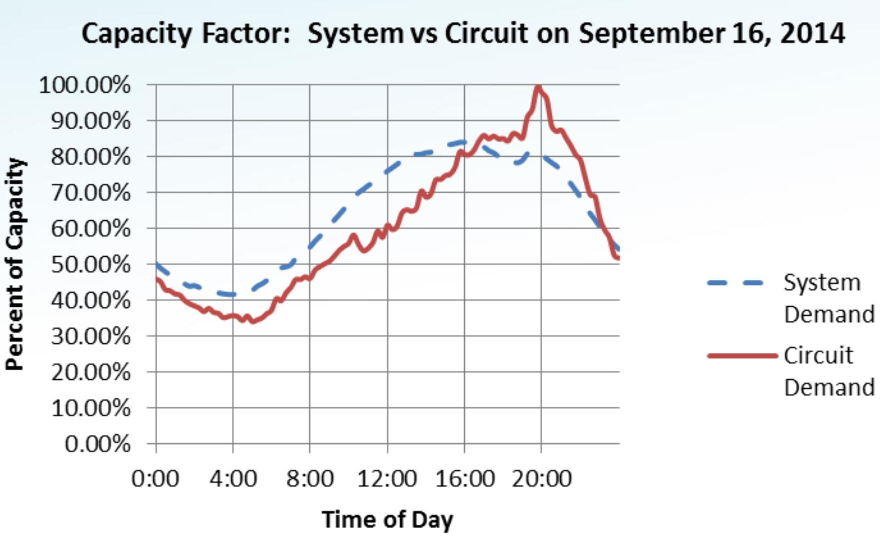
Ch. 5: Support for Non-Coincident Demand Charge

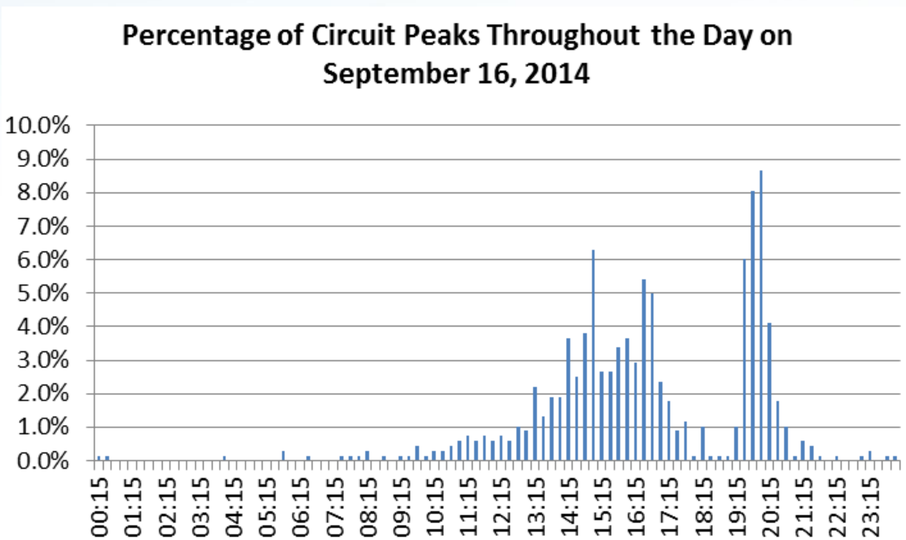
- Distribution needs are local
- Each circuit on the distribution system has different growth characteristics, driven by:
  - Customer profile (residential, commercial, etc)
  - Local weather conditions
  - Stage of development
- Engineers evaluate each circuit independently for appropriate plans of service



Ch. 5: Support for Non-Coincident Demand Charge

- Non-coincident demand drives Distribution needs
- Distribution circuits experience peak demand at different times
  - Not coincident with system peak
  - Need to be addressed individually to preserve reliability
  - Non-coincident demand charge is best tool to address peak circuit demand





Ch. 6: Distribution Marginal Cost Studies and Allocations

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Distribution Marginal Costs

- Marginal Distribution Customer Costs:
  - Developed based on the Rental Method.
  - Represent the cost of providing an individual customer access to electrical service:
    - Costs associated with the investment required to provide access (hook up) to a new customer, which consist of transformers, services, meters ("TSM") costs.
    - Ongoing costs of maintaining the new customer such as Customer-Related O&M costs and Customer Services costs.
  - These costs vary by customer type, service voltage, and type of equipment used for access.
- Marginal Distribution Demand Costs:
  - Developed based on the National Economic Research Associates ("NERA") Regression Method.
  - Represent the cost of providing facilities from the substation to the customer access point in order to meet the customer's individual demands.

Ch. 6: Distribution Marginal Cost Studies and Allocations

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Distribution Revenue Allocation

- Developed based on proposed marginal distribution customer and demand costs.
- Unit distribution marginal costs multiplied by appropriate cost drivers to develop marginal distribution revenue allocations by customer class.
  - Marginal distribution customer cost revenues developed by multiplying the unit marginal distribution customer costs by the forecasted number of customers.
  - Marginal distribution demand cost revenues developed by multiplying the customer class' annual non-coincident demand, the applicable loss factors and the calculated ratio of the average class contribution to the peak demand at the circuit level (Effective Demand Factor or "EDF").
- Resulting marginal distribution revenues scaled by the Equal Percent of Marginal Cost ("EPMC") factor to ensure recovery of authorized revenues.

Ch. 7: Commodity Marginal Cost Studies and Allocations, CTC Allocations

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- Commodity Marginal Costs:
  - Marginal Energy Costs ("MEC"): Future hourly electricity prices aggregated by Time-of-Use ("TOU") period
    - Based on SP-15 forward prices and net load price shape.
    - Added Renewable Portfolio Standard ("RPS") adder evenly to each TOU period.
  - Marginal Generation Capacity Costs ("MGCC"): Cost of building a new Combustion Turbine ("CT") minus expected earnings.
    - Based on cost estimates from California Energy Commission's ("CEC") Estimated Cost of New Renewable and Fossil Generation in California Report and CAISO Department of Market Monitoring Annual Report on Market Issues & Performance

Ch. 7: Commodity Marginal Cost Studies and Allocations, CTC Allocations

- Commodity Revenue Allocation:
  - MEC allocated to each class based on kWh used in each TOU period x MEC.
  - MGCC allocated to each class based on average load in top 100 hours with highest Loss of Load Expectation ("LOLE") x MGCC.
- Competition Transition Charge ("CTC") Revenue Allocation
  - Updated top 100 hours of system load used in revenue allocation for more recent 3 years of data.

Ch. 8: Stakeholder Outreach efforts and ME&O Plan

Stakeholder Outreach Efforts

- **CAISO** (November 5):
  - Supportive of updated TOU periods
  - Recognizes need for simplification for customer understandability.
- **Farm Bureau** (November 9):
  - Liked the shorter TOU periods and the different period for CPP
  - Concern about general winter on-peak and also off-peak from 2-4pm.
- **Major Customer Advisory Panel "MCAP"** (November 17)
- **ORA** (November 10):
  - Follow-up regarding having a different TOU period for on-peak and CPP
  - Follow-up regarding model functionality
- **UCAN** (November 9):
  - "A lot that I like about this" but wanted to make sure that it serves the needs of all customers
- **Water Districts** (November 12-13)
  - SDCWA: concerns include on-peak now 7 days a week and impact of maintenance run on NCD (noted super-off peak exemption)
- **Schools** (November 18)
  - Sent written proposal to coalition's legal department.
- **Street Lighting Workshop** (February 19)
  - Initial meeting with CALSLA, City of San Diego, City of Chula Vista, and others.

Ch. 8: Proposal for Schedule A Compliance

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- Decision language: "SDG&E will modify the applicability for Schedule A to address its current availability to large customers."
- Schedule A Compliance Proposal
  - Modified applicability: This schedule is not applicable to any customer whose Maximum Monthly Demand equals, exceeds, or is expected to equal or exceed 20 kW for 12 consecutive months **and whose demand exceeds 200 kW in 2 out of the 12 consecutive months**. When demand metering is not available, the monthly consumption cannot equal or exceed 12,000 kWh per month for 12 consecutive months. This schedule is the utility's standard tariff for commercial customers with a demand less than 20 kW.
- New rate option introduced to provide a transition path for demand-based rate to certain ineligible customers

Ch.9: Updated CPP Trigger Threshold

- Allow the CPP-D trigger to be reached when load reduction is needed
  - In 2012 and 2013 SDG&E was unable to call CPP on its system peak days as the current trigger was not reached.
  - SDG&E proposes to replace the requirement for the day ahead actual system load at 2:30 p.m. to be greater than 3,837 MW with the requirement that the forecasted system load be greater than 4,000 MW.
- Enable day-ahead CPP-D event decisions before 2:30 p.m.
  - Additionally, having the flexibility to call CPP events earlier in the day would allow SDG&E to notify customers of next day events sooner.
- Add transparency to SDG&E's Dynamic Rate Triggers
  - Currently SPP and PTR trigger language is not specific and leverages the CPP trigger language. SDG&E proposes to make the trigger language similar for all its dynamic rates.
- Align the triggers for all of SDG&E's dynamic rate schedules
  - Alignment of SPP Plus and Schedule PTR triggers with CPP-D will add consistency and transparency to SDG&E's dynamic rates.
  - Consistent with D.14-05-025, OP1 directive.