Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 15-04-012
Exhibit No.: SDG&E-11

PREPARED REBUTTAL TESTIMONY OF

CYNTHIA FANG

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF

SECOND AMENDED APPLICATION

CHAPTER 1

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

August 30, 2016

TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY OF

CYNTHIA FANG

(CHAPTER 1)

I. OVERVIEW AND PURPOSE

The purpose of my rebuttal testimony is to respond to the prepared direct testimony submitted by intervening parties in San Diego Gas & Electric's ("SDG&E") 2016 General Rate Case ("GRC") Phase 2 Application (A.15-04-012) on policy issues related to SDG&E's electric rate design proposals in this proceeding. In addition, through this rebuttal testimony, I am assuming responsibility for sponsoring Section III of the February 9, 2016 Direct Testimony of SDG&E witness Christopher Swartz,[1] which addressed revenue allocation. As such, I also will respond to the prepared direct testimony submitted by intervening parties on SDG&E's revenue allocation proposal. Specifically, I will address rate design policy and revenue allocation recommendations presented by the following parties ("Parties"):

- Office of Ratepayer Advocates ("ORA") witnesses Eric Duran (Sales Forecast), Aaron Lu (Revenue Allocation), Cherie Chan (Residential Rate Design) and Nathan Chau (Small Commercial Rate Design).
- Federal Executive Agencies ("FEA") witness Maurice Brubaker.
- California Farm Bureau Federation ("Farm Bureau") witnesses Laura Norin and Brandon Charles.
- Solar Energy Industries Association ("SEIA") witness R. Thomas Beach.
- California City-County Street Lighting Association ("CALSLA") witness Alison Lechowicz.

---

[1] SDG&E Direct Testimony of Christopher Swartz, Chapter 2, pages CS-8, line 1 to CS-20, line 11.

- The Utility Reform Network ("TURN") witness William Perea Marcus.
- Utility Consumers Action Network ("UCAN") witnesses Garrick F. Jones and William Perea Marcus.
- California Solar Energy Industries Association ("CALSEIA") witness Kevin Weinberg.
- City of San Diego ("CSD" or "City of San Diego") witness William A. Monsen.
- San Diego County Water Agencies ("Water Agencies") witness Dr. Lon W. House.
- The San Diego Public Schools ("Schools") witnesses Dr. Lon W. House, Lora Duzyk and Dr. Gina Potter.

In addition, rebuttal testimony is provided by the following SDG&E witnesses:

- Christopher Swartz (Chapter 2) in response to parties on issues related to SDG&E's rate design proposals.
- Robert B. Anderson (Chapter 3) in response to ORA's Loss of Load Expectation ("LOLE") analysis.
- Kenneth Schiermeyer (Chapter 4) in response to parties on issues related to the proposed sales forecast.
- William G. Saxe (Chapter 5) in response to parties on issues related to SDG&E's proposed distribution marginal costs.
- Jeffrey J. Shaughnessy (Chapter 6) in response to parties on issues related to SDG&E's proposed commodity marginal costs.
- Leslie Willoughby (Chapter 7) in response to UCAN's supplemental testimony regarding SDG&E's electric demand factors ("EDFs").

The rebuttal testimony sponsored by SDG&E witnesses Mr. Schiermeyer and Ms. Willoughby in response to the testimony provided by parties includes updates to the sales forecast and the EDFs, which result in the following impacts discussed in more detail below:

- 2016, 2017 and 2018 Sales Forecast. The rebuttal testimony of Mr. Schiermeyer includes an update to SDG&E's proposed 2016, 2017 and 2018 sales forecast to reflect the California Energy Commission's ("CEC") most recent approved forecast. The updated sales forecast impacts the results of: (1) the cost-based revenue allocations presented in the rebuttal testimonies of Mr. Saxe and Mr. Shaughnessy; (2) revenue allocations presented in this rebuttal testimony; and (3) the rate and bill impacts presented in the rebuttal testimony of Mr. Swartz. Table 1 below compares the current sales forecast update to prior SDG&E sales forecasts, which are discussed in further detail in the rebuttal testimony of Mr. Schiermeyer.

TABLE 1: COMPARISON OF UPDATED SDG&E SALES FORECAST

Comparison of Annual Electric Sales (GWh)							
Sector	GRC Phase 1 TY 2016	GRC Phase 2 TY 2016	GRC Phase 2 TY 2017	GRC Phase 2 TY 2018	GRC Phase 2 Rebuttal TY 2016	GRC Phase 2 Rebuttal TY 2017	GRC Phase 2 Rebuttal TY 2018
Residential	7,681	7,378	7,331	7,266	6,944	6,803	6,608
Non-Residential	12,332	12,302	12,286	12,293	12,731	12,799	12,795
Total	**20,013**	**19,680**	**19,616**	**19,559**	**19,675**	**19,602**	**19,403**

- Updated EDFs: The EDFs are a primary driver in the allocation of distribution demand costs. In response to opening testimony from UCAN, the rebuttal testimony of Ms. Willoughby recommends a revision to the EDFs used by Mr. Saxe in the allocation of distribution demand costs to customer classes. The updated EDFs impact the results of: (1) the allocation of distribution demand revenues presented in the rebuttal testimony of Mr. Saxe; (2) revenue allocations presented in this rebuttal testimony; and (3) the rate and bill impacts presented in the rebuttal testimony of Mr. Swartz. Table 2 below compares the updated EDFs used in SDG&E's rebuttal to the prior EDFs used in SDG&E's direct testimony and are discussed in further detail in the rebuttal testimony of Ms. Willoughby.

TABLE 2: COMPARISON OF UPDATED EFFECTIVE DEMAND FACTORS

	Substation EDFs		Circuit EDFs	
	Direct	**Rebuttal**	**Direct**	**Rebuttal**
Residential	52.16%	**28.24%**	54.96%	**35.93%**
Small Commercial	61.65%	**44.69%**	65.14%	**44.32%**
M/L C&I	64.81%	**68.41%**	72.06%	**72.35%**
Agricultural	35.87%	**29.58%**	35.25%	**36.72%**
Streetlighting	44.56%	**40.35%**	29.15%	**45.76%**

- Impact to revenue allocations: The update to sales results in the following updates to revenue allocations: (1) Distribution, based on the updated allocation factors resulting from the updated Distribution Cost Studies presented in the rebuttal testimony of Mr. Saxe; (2) Commodity, based on the updated allocation factors resulting from the updated Commodity Cost Studies presented in the rebuttal testimony of Mr. Shaughnessy; (3) Competition Transition Charge ("CTC"), based on the updated allocation factors resulting from the updated study presented in the rebuttal testimony of Mr. Shaughnessy; (4) California Alternative Rate for Energy ("CARE")/Family Electric Rate Assistance ("FERA"), Energy Savings Assistance Program ("ESAP") and Electric Program Investment Charge ("EPIC") to reflect the updated 2016 sales presented in the rebuttal testimony of Mr. Schiermeyer. The updated allocation factors are discussed in more detail below.

In addition, my rebuttal testimony introduces SDG&E's School Proposal. SDG&E recognizes the special circumstances the public schools face, such as their limited budget control and inability to change use patterns tied to periods during which they must serve the needs of children and SDG&E is committed to working with the public schools to find a solution. In response to concerns expressed in the Schools' testimony, SDG&E proposes to provide a 10% line-item discount to the electric bills of public schools K-12 in SDG&E's service territory.

My rebuttal testimony addresses the recommendations of the Parties regarding rate design principles and revenue allocations and is organized as follows:

- **Section II –** Updates to Reflect the Most Current Available Information
- **Section III –** Revenue Allocation
- **Section IV –** Time-of-Use ("TOU") Periods
- **Section V –** Cost-Based Rates
- **Section VI –** Other Policy Issues:
  - a) Residential Rate Reform
  - b) Regulatory Vehicle for Annual Sales Updates
  - c) New School Proposal
  - d) Implementation Timing
- **Section VII –** Summary and Conclusion

II. UPDATES TO REFLECT THE MOST CURRENT AVAILABLE INFORMATION

In response to opening testimony from the interested parties identified above, SDG&E provides the following updates in its rebuttal testimony:

- <u>Current effective rates August 1, 2016</u>.[2] SDG&E's Second-Amended Application was developed based on rates effective November 1, 2015. Rates have since changed. Current rates, effective August 1, 2016, now reflect, among other things, the implementation of the California Public Utilities Commission's ("Commission") decision in SDG&E's 2016 GRC

---

[2] SDG&E Advice Letter ("AL") 2922-E.

Phase 1 application[3] and the 2016 Glidepath implementation of Residential Rate Reform ("RROIR").[4] To ensure that the parties and the Commission have the best information available to assess the impacts of the proposals in this proceeding, SDG&E has updated its proposals to be revenue neutral based on current and effective rates as of August 1, 2016. This update is reflected in revenues referenced for allocation in the rebuttal testimonies of Mr. Saxe, Mr. Shaughnessy and presented below, as well as in the rate and bill impacts presented in the rebuttal testimony of Mr. Swartz.

The rebuttal testimony of Mr. Swartz maintains the current-effective tier differentials associated with the 2016 Glidepath[5] in the residential rates presented throughout the years included in this proceeding.

- NEM 2.0 Update. D.16-01-044 required that customers on the Net Energy Metering ("NEM") successor tariff pay non-bypassable charges ("NBCs") that are levied on each kilowatt-hour ("kWh") of electricity the customer obtains from the investor-owned-utility ("IOU") in each metered time interval, regardless of the monthly netting of the kWh as a result of energy exported to the grid by the customer,[6] with non-bypassable charges defined as the Public Purpose Program Charge ("PPP"), Nuclear Decommissioning Charge ("ND"), Competition Transition Charges ("CTC") and Department of Water Resources Bond Charges ("DWR-BC").[7] Resolution E-4792 (issued June 24, 2016) clarifies that the D.16-01-044 directive to assess NBCs on the "metered" interval should be interpreted to mean that imported and exported kWh to and from the grid should be "netted" in each metered interval

---

3 Decision ("D.") 16-06-054 and SDG&E AL 2917-E/2490-G.
4 SDG&E AL 2861-E-A.
5 AL 2922-E; AL 2783-E.
6 D.16-01-044, page 3.
7 D.16-01-044, page 89.

and NBCs should only be charged on the "net" kWh imported from the grid in any given metered interval. In rebuttal, SDG&E updates its sales determinants used for rate design such that only the sales determinants applied to the PPP, ND, CTC and DWR-BC rate components are based on delivered energy,[8] while the sales determinants based on net energy[9] are applied to the remaining rate components to best approximate the results of D.16-01-044 and Resolution E-4792.

In addition, SDG&E provides further clarification regarding its proposal to move recovery of costs relating to the California Solar Initiative ("CSI") and the Self-Generation Incentive Program ("SGIP") from distribution rates to PPP rates and the request that CSI and SGIP costs be recovered on the basis of delivered energy consistent with current costs recovered through PPP rates under D.16-01-044.

- <u>Revenue Allocations</u>: Since the submittal of SDG&E's 2016 GRC Phase 2 Second Amended Application and Testimony on February 9, 2016, more recent data is now available that provides the basis for the allocation of Energy Efficiency ("EE") and the Local Generation Charge ("LGC"). As such, SDG&E proposes to update these allocation factors for the most current information, specifically: (1) EE to reflect 2016 forecasted spend now available and (2) LGC to reflect the most recent 12-month coincident peak as presented in SDG&E's Fourth Transmission Owner ("T04") Formula Rate Mechanism, Federal Energy Regulatory Commission ("FERC") Docket No. ER16-445-000.

Any additional updates, including revisions to SDG&E's sales forecast and EDFs, are discussed by their respective witnesses.

---

8 Delivered sales represent the sales provided to the customer that would have otherwise been netted out by excess generation on an hourly basis.

9 Net sales represent R1 sales, reported in SDG&E's Electric Revenue Reporting, with the adjustment to account for excess solar photovoltaic generation that occurs on a monthly basis.

III. REVENUE ALLOCATION

As noted above, through this rebuttal testimony, I am assuming responsibility for sponsoring Section III of the February 9, 2016 Direct Testimony of Christopher Swartz,[10] which addressed SDG&E's proposals for revenue allocation.

A. Updates to Revenue Allocation

In this rebuttal, SDG&E provides the updated allocation factors for the following costs: (1) Distribution, based on the updated allocation factors resulting from the updated Distribution Cost Studies and allocation factors presented in the rebuttal testimony of Mr. Saxe; (2) Commodity, based on the updated allocation factors resulting from the updated Commodity revenue allocation presented in the rebuttal testimony of Mr. Shaughnessy; (3) CTC, based on the updated allocation factors resulting from the updated study presented in the rebuttal testimony of Mr. Shaughnessy; (4) CARE/FERA, ESAP and EPIC to reflect the updated 2016 sales presented in the rebuttal testimony of Mr. Schiermeyer; (5) EE to reflect 2016 forecasted spend now available; (6) LGC to reflect the most recent 12-month coincident peak as presented in SDG&E's Fourth Transmission Owner ("T04") Formula Rate Mechanism, FERC Docket No. ER16-445-000 and (7) CSI and SGIP to reflect the move of Schedule PA-T-1 from the medium/large commercial and industrial ("M/L C&I") class to the Agricultural class. The updated allocation factors are discussed in more detail below.

Table 3 below presents the updated revenue allocation factors for Distribution and Commodity that result from the updated cost-based allocations presented in the testimony of Mr. Saxe and Mr. Shaughnessy, respectively. In SDG&E's direct testimony, SDG&E proposed a 3-year transition to reach its revenue allocation proposal for Distribution and Commodity.

[10] SDG&E Direct Testimony of Christopher Swartz, Chapter 2, pages CS-8, line 1 to CS-20, line 11.

Currently, Distribution and Commodity make up 29% and 47% of SDG&E's system average rate, respectively.[11] Table 4 presents SDG&E's proposed 3-year transition towards its full cost-based Distribution and Commodity revenue allocation proposals.

TABLE 3: UPDATED REVENUE ALLOCATION FACTORS – DISTRIBUTION AND COMMODITY

	Current	Direct	Rebuttal	%Change from Current	%Change from Direct
Distribution					
Residential	47.58%	54.19%	48.57%	2.09%	-10.38%
Small Commercial	12.67%	14.37%	15.82%	24.82%	10.06%
M/L C&I	37.70%	29.74%	33.60%	-10.87%	13.00%
Agricultural	1.33%	1.05%	1.23%	-7.61%	17.12%
Streetlighting	0.72%	0.65%	0.78%	8.33%	20.69%
Commodity					
Residential	45.69%	48.71%	46.35%	1.44%	-4.85%
Small Commercial	11.34%	11.83%	13.18%	16.22%	11.39%
M/L C&I	41.02%	37.33%	38.48%	-6.20%	3.07%
Agricultural	1.53%	1.64%	1.53%	0.10%	-6.65%
Streetlighting	0.42%	0.49%	0.47%	9.79%	-4.29%

[11] Based on 8/1/16 effective rates per AL 2922-E, and includes the California Climate Credit.

TABLE 4: 3-YEAR TRANSITION PLAN FOR UPDATED DISTRIBUTION AND COMMODITY REVENUE ALLOCATION FACTORS

	Current [12]	Proposed Year 1	Proposed Year 2	Proposed Year 3	% Change Year 3 Compared to Current
Distribution					
Residential	47.58%	47.91%	48.24%	48.57%	2.09%
Small Commercial	12.67%	13.72%	14.77%	15.82%	24.82%
M/L C&I	37.70%	36.33%	34.97%	33.60%	-10.87%
Agricultural	1.33%	1.30%	1.27%	1.23%	-7.61%
Streetlighting	0.72%	0.74%	0.76%	0.78%	8.33%
Commodity					
Residential	45.69%	45.91%	46.13%	46.35%	1.44%
Small Commercial	11.34%	11.95%	12.56%	13.18%	16.22%
M/L C&I	41.02%	40.17%	39.33%	38.48%	-6.20%
Agricultural	1.53%	1.53%	1.53%	1.53%	0.10%
Streetlighting	0.42%	0.44%	0.45%	0.47%	9.79%

SDG&E's response to parties' comments regarding SDG&E's Distribution and Commodity allocation factors resulting from its marginal Distribution and Commodity cost studies are addressed in the rebuttal testimony of Mr. Saxe and Mr. Shaughnessy, respectively.

Table 5 below presents the updated revenue allocation factors for CTC that result from the updated study presented in the testimony of Mr. Shaughnessy as well as the updated allocation factors for LGC. Currently, CTC and LGC make up 0.8% and 0.2% of the system average rate, respectively.[13]

---

[12] Current for Distribution includes Standby, Distance Adjustment, and Lighting Facilities revenues.
[13] Based on 8/1/16 effective rates per AL 2922-E, and includes the California Climate Credit.

TABLE 5: UPDATED REVENUE

ALLOCATION FACTORS – CTC AND LGC

	Current	Direct	Rebuttal	%Change from Current	%Change from Direct
CTC					
Residential	40.89%	40.79%	38.55%	-5.71%	-5.49%
Small Commercial	11.61%	11.29%	12.56%	8.21%	11.34%
M/L C&I	46.48%	46.80%	47.79%	2.82%	2.11%
Agricultural	1.02%	1.10%	1.06%	3.89%	-3.75%
Streetlighting	0.00%	0.02%	0.03%	N/A	N/A
LGC					
Residential	40.89%	40.89%	41.76%	2.13%	2.13%
Small Commercial	11.03%	11.03%	10.83%	-1.88%	-1.88%
M/L C&I	46.81%	46.81%	46.15%	-1.41%	-1.41%
Agricultural	0.89%	0.89%	0.90%	1.02%	1.02%
Streetlighting	0.38%	0.38%	0.37%	-2.88%	-2.88%

PPP includes the recovery of costs associated with the following programs: CARE/FERA, ESAP, EPIC and EE. Table 6 presents the updated revenue allocation factors for the components of PPP.

TABLE 6: UPDATED REVENUE ALLOCATION FACTORS – PPP COMPONENTS

	Current	Direct	Rebuttal	%Change from Current	%Change from Direct
CARE[14]					
Residential	33.43%	34.27%	32.47%	-2.89%	-5.25%
Small Commercial	10.11%	10.79%	11.91%	17.81%	10.43%
M/L C&I	56.02%	53.18%	53.97%	-3.65%	1.49%
Agricultural	0.44%	1.77%	1.65%	276.86%	-6.73%
Streetlighting	0.00%	0.00%	0.00%	N/A	N/A
ESAP					
Residential	37.88%	38.38%	36.15%	-4.56%	-5.82%
Small Commercial	9.44%	10.11%	11.26%	19.33%	11.36%
M/L C&I	52.28%	49.85%	51.03%	-2.38%	2.37%
Agricultural	0.41%	1.65%	1.55%	281.78%	-5.91%
Streetlighting	0.00%	0.00%	0.00%	N/A	N/A
EPIC					
Residential	41.30%	38.21%	35.99%	-12.85%	-5.80%
Small Commercial	14.00%	10.06%	11.21%	-19.93%	11.39%
M/L C&I	43.50%	49.62%	50.81%	16.80%	2.39%
Agricultural	0.50%	1.64%	1.55%	209.50%	-5.89%
Streetlighting	0.70%	0.46%	0.44%	-36.89%	-4.57%
EE					
Residential	34.52%	36.28%	46.05%	33.41%	26.93%
Small Commercial	15.13%	14.57%	11.30%	-25.30%	-22.44%
M/L C&I	49.28%	47.47%	41.45%	-15.90%	-12.69%
Agricultural	0.60%	1.29%	1.12%	85.44%	-13.60%
Streetlighting	0.47%	0.38%	0.08%	-81.93%	-77.91%

Table 7 presents the effective change to the allocation of PPP by class that results due to the updated revenue allocation factors for each component of PPP, as presented in Table 6 above. Currently, PPP makes up 6% of the system average rate.[15]

[14] Now includes FERA, pursuant to SDG&E AL-2795-E.
[15] Based on 8/1/16 effective rates per AL 2922-E, and includes the California Climate Credit.

TABLE 7: UPDATED REVENUE ALLOCATION FACTORS – TOTAL PPP[16]

	Current	Direct	Rebuttal	%Change from Current	%Change from Direct
PPP					
Residential	34.55%	36.43%	38.26%	10.74%	5.01%
Small Commercial	12.31%	11.81%	11.60%	-5.80%	-1.84%
M/L C&I	52.41%	50.37%	48.66%	-7.15%	-3.39%
Agricultural	0.51%	1.21%	1.43%	182.14%	17.76%
Streetlighting	0.23%	0.17%	0.06%	-73.87%	-65.92%

B. Intervenor Testimony Addressing Revenue Allocation

The following parties provided testimony regarding SDG&E's revenue allocation proposals:

- Allocations for CSI, SGIP and DR: ORA witness Aaron Lu[17] and FEA witness Maurice Brubaker.[18]
- Revenue Allocation Caps: ORA witness Aaron Lu,[19] Farm Bureau witness Laura Norin,[20] CALSLA witness Alison Lechowicz[21] and UCAN witnesses Garrick F. Jones and William Perea Marcus.[22]

SDG&E responds to these parties' revenue allocation testimony below.

---

16 While Current PPP allocation factors per component did not change from the Current allocation factors presented in direct testimony, the Updated allocation of Current Total PPP does change from direct testimony, due to the move of the CARE Rate Subsidy to a line item discount, and the addition of FERA line item discount.

17 ORA Direct Testimony, Witness Lu, page 6-11, lines 1-5.

18 FEA Direct Testimony, Witness Brubaker, page 20, line 18 – page 21, line 2.

19 ORA Direct Testimony, Witness Lu, page 6-11, line 21 – page 6-12, line 2.

20 Farm Bureau Direct Testimony, Witness Norin, page 18, lines 1-4.

21 CALSLA Direct Testimony, Witness Lechowicz, page 10, lines 11-15.

22 UCAN Direct Testimony, Witnesses Jones and Marcus, page 40.

1. Allocations for CSI, SGIP and DR

SDG&E, in this proceeding, has proposed no change to the current and effective customer class allocations of program costs related to CSI, SGIP and Demand Response ("DR"), although SDG&E did propose to move the recovery of CSI and SGIP from distribution rates to PPP rates to ensure a more equitable recovery of the costs of these public policy programs. CSI and SGIP are incentive programs intended to further State and Commission objectives related to customer adoption of solar and Distributed Energy Resources ("DER"). As such, the costs of these incentive programs are more like the program costs currently recovered through the PPP rates, such as costs related to the CARE and FERA programs (which provide subsidies for low-income customers), the ESAP program (which provides subsidies in support of energy efficiency objectives for low-income customers), the EE program (which provides incentives in support of energy efficiency objectives) and the EPIC program (which provides incentives in support of new and emerging clean energy technologies). While ORA provided comments regarding updating CSI and SGIP allocations for updated sales, ORA remained silent regarding SDG&E's proposal to move the recovery of CSI and SGIP costs from Distribution to PPP. While silent on SDG&E's proposal to move CSI and SGIP recovery to PPP, the overarching public policy benefits of the CSI and SGIP programs are nonetheless recognized by ORA in its testimony:[23]

> *The SGIP and CSI are programs that exist to provide broad environmental benefits for all California ratepayers. These programs offer incentives to IOU customers to install distributed generation to fulfill California's energy policy goals. The Commission found in its decision adopting the initial SGIP*

---

[23] ORA Direct Testimony, Witness Lu, page 6-9, lines 15-26.

program that, "The self-generation programs … will produce significant public (e.g., environmental) benefits for all ratepayers."[24] In addition, the Commission, in its CSI adoption decision stated, "The development of solar energy projects is consistent with state policies generally that support environmentally sound energy resources and an energy infrastructure that is diverse and disbursed."[25] The decision also found that "All solar energy technologies have the potential to reduce demand for fossil fuels and investments in more traditional energy resources and provide environmental benefits."[26]

Transferring recovery of the CSI and SGIP costs to the PPP rate component not only aligns the recovery of these programs with that of like incentive programs, but also ensures that NEM customers actually fund programs that they have likely benefitted from, or may still benefit from. The "netting" mechanism under the NEM program has allowed customers to bypass the recovery of costs collected through energy rates with the adoption of solar or other NEM-eligible generators. D.16-01-044 continued the basic features of the prior NEM program (including the netting mechanism) in the successor NEM tariff. However, under the NEM successor tariff, customers are required to pay non-bypassable charges that are levied on each kWh of electricity that the customer obtains from the IOU in each metered time interval, regardless of the monthly netting of the kWh obtained from the IOU and exported to the grid by the customer,[27] with non-

---

[24] D.01-03-073, mimeo, Finding of Fact #3, page 40.
[25] D.06-01-024, mimeo, page 12.
[26] Id., Finding of Fact #5, page 39.
[27] D. 16-01-044, page 3.

bypassable charges limited to PPP, ND, CTC and DWR-BC.[28] SDG&E's proposal to move the recovery of CSI and SGIP costs from Distribution to PPP would include these costs as non-bypassable, as defined in D.16-01-044, consistent with current PPP costs. Only in this way, will all benefitting customers contribute to the costs of these programs.

In response to SDG&E's current allocation of program costs related to CSI and SGIP to customers, which was established as part of a settlement agreement in SDG&E's 2008 GRC Phase 2 proceeding,[29] ORA proposes to update the SGIP allocations to an equal cents per kWh allocator or a total sales percentage allocator. Additionally, ORA proposes an equal cents per kWh allocator for CSI, exempting CARE customers.[30]

Table 8 below provides a comparison of the current allocation factors for CSI and SGIP to what they would be if they were updated to reflect the updated 2016 sales. SDG&E does not propose to change the factors for the allocation of CSI and SGIP costs to the customer classes at this time, with the exception of moving PA-T-1 from the M/L C&I class to the Agricultural class (consistent with the movement of Schedule PA-T-1 from the M/L C&I customer class to the Agricultural customer class, as agreed to in the settlement approved in D.14-01-002).[31]

---

28 D. 16-01-044, page 89.
29 D.08-02-034, in A. 07-01-047.
30 ORA Direct Testimony, Witness Lu, page 6-11, lines 3-5.
31 TY 2012 GRC Phase 2 (A.11-10-002) October 4, 2012 Partial Settlement Agreement, Section 3.C – Schedule PA-T-1, pp. 7-11.

TABLE 8: REVENUE ALLOCATION FACTORS – CSI AND SGIP

	Current	SDG&E Proposal (reflects PA-T-1 move)[32]	ORA: Based on Updated 2016 Sales	% Change PA-T-1 Move to Current	%Change from ORA to Current
			CSI		
Residential	41.55%	41.55%	32.32%	0.00%	-22.22%
Small Commercial	11.37%	11.37%	11.86%	0.00%	4.25%
M/L C&I	46.09%	44.96%	53.72%	-2.45%	16.56%
Agricultural	0.46%	1.59%	1.64%	244.89%	255.17%
Streetlighting	0.53%	0.53%	0.47%	0.00%	-11.47%
			SGIP		
Residential	41.55%	41.55%	35.99%	0.00%	-13.37%
Small Commercial	11.37%	11.37%	11.21%	0.00%	-1.43%
M/L C&I	46.09%	44.96%	50.81%	-2.45%	10.24%
Agricultural	0.46%	1.59%	1.55%	244.53%	235.39%
Streetlighting	0.53%	0.53%	0.44%	0.00%	-16.40%

Tables 9 and 10 below respectively present the total revenue allocation assigned to each class, and change in total revenues allocated to each customer class.

TABLE 9: SUMMARY OF ILLUSTRATIVE

TOTAL REVENUE ALLOCATIONS

	Current[33]	2016	% Change from Current to 2016	2017	% Change from Current to 2017	2018	% Change from Current to 2018
Revenue Allocations							
Residential	44.03%	44.34%	0.70%	44.41%	0.87%	44.48%	1.03%
Small Commercial	11.97%	12.76%	6.62%	13.40%	11.95%	14.05%	17.34%
M/L C&I	42.12%	41.05%	-2.54%	40.34%	-4.23%	39.62%	-5.93%
Agricultural	1.38%	1.35%	-2.18%	1.33%	-2.97%	1.32%	-3.72%
Streetlighting	0.51%	0.50%	-0.87%	0.52%	1.46%	0.53%	3.96%

32 Based on 8/1/16 effective rates per AL 2922-E.
33 Based on 8/1/16 effective rates per AL 2922-E.

TABLE 10: IMPACT OF PROPOSED REVENUE ALLOCATIONS CHANGES RELATIVE TO CURRENT– DIRECT VS REBUTTAL

	Direct (Year 1)	Direct (Year 2)	Direct (Year 3)	Rebuttal (Year 1)	Rebuttal (Year 2)	Rebuttal (Year 3)
Revenue Allocations						
Residential	3.64%	6.43%	9.21%	0.70%	0.87%	1.03%
Small Commercial	1.86%	4.12%	6.38%	6.62%	11.95%	17.34%
M/L C&I	-4.25%	-7.73%	-11.22%	-2.54%	-4.23%	-5.93%
Agricultural	-1.21%	-2.39%	-3.58%	-2.18%	-2.97%	-3.72%
Streetlighting	-0.25%	0.64%	1.54%	-0.87%	1.46%	3.96%

2. Revenue Allocation Caps

Several parties (ORA,[34] UCAN,[35] CALSLA[36] and Farm Bureau[37]) propose capping in order to limit the impact that updated allocation factors would have to certain customer classes. In addition to limiting the impact that increases would have to certain customer classes, capping would conversely limit the benefits that other customer classes may see, despite the fact that these benefits may be warranted based on the updated cost studies presented in this filing. The question of changing the allocation of costs to different customer classes is a challenging one. For this reason, SDG&E continues to propose a transition, rather than capping, in order to more equitably address all of its customer classes, i.e., both the customer classes that are seeing increased allocations as a result of updated cost studies, and the classes that are seeing decreased allocations as a result of the same updated cost studies.

[34] ORA Direct Testimony, Witness Lu, Chapter 6, page 6-12.
[35] UCAN Direct Testimony, page 40.
[36] CALSLA Direct Testimony, Witness Lechowicz, page 10, lines 11-15.
[37] Farm Bureau Direct Testimony, Witness Norin, page 18, lines 1-5.

IV. TIME-OF-USE ("TOU") PERIODS

Parties, specifically ORA,[38] Farm Bureau,[39] and SEIA,[40] provided alternative proposals for TOU period definitions that included different definitions of on-peak, off-peak and super off-peak periods, different numbers of TOU periods and different seasonal definitions. Table 11 below provides a summary of the TOU period proposals presented by these parties.

TABLE 11: COMPARISON OF TOU PERIOD PROPOSALS

	On-peak	Super off-peak	Off-peak
SDG&E Proposal			
Summer: May to October			
Summer Weekdays	4 pm to 9 pm	12 am to 6 am	all other hours
Summer Weekends	4 pm to 9 pm	12 am to 2 pm	all other hours
Winter: November to April			
Winter Weekdays	4 pm to 9 pm	12 am to 6 am	all other hours
Winter Weekends	4 pm to 9 pm	12 am to 2 pm	all other hours
ORA Proposal			
Summer: July to October			
Summer Weekdays	4 pm to 9 pm	N/A	all other hours
Summer Weekends	N/A	N/A	All
Winter: November to June			
Winter Weekdays	4 pm to 9 pm	N/A	all other hours
Winter Weekends	N/A	N/A	All
Farm Bureau Proposal			
Summer: May to October			
Summer Weekdays	4 pm to 9 pm	12 am to 2 pm	all other hours
Summer Weekends	4 pm to 9 pm	12 am to 4 pm	all other hours
Winter: November to April			
Winter Weekdays	4 pm to 9 pm	12 am to 2 pm	all other hours
Winter Weekends	4 pm to 9 pm	12 am to 4 pm	all other hours
SEIA Proposal			
Summer: May to October			
Summer Weekdays/Weekends	2 pm to 7 pm	10 pm to 6 am	all other hours
Winter: November to April			
Winter Weekdays/Weekends	4 pm to 8 pm	10 pm to 6 am	all other hours

[38] ORA Direct Testimony, page viii, line 5.
[39] Farm Bureau Direct Testimony, Witness Norin, page 6, line 1.
[40] SEIA Direct Testimony, Witness Beach, page 7, line 1.

A. Definition of On-peak Period

SDG&E's proposed TOU periods redefine the current on-peak period of 11 a.m. to 6 p.m. to be 4 p.m. to 9 p.m. Many parties recognize the need to change the on-peak period to later in the day and ORA and the Farm Bureau support a new on-peak period definition of 4 p.m. to 9 p.m. In contrast, some parties (1) continue to deny the need to change TOU periods at all (Water Districts[41]), (2) argue for grandfathering TOU periods (CALSEIA,[42] Schools,[43] SEIA,[44] City of San Diego[45]), (3) argue for limited change to TOU periods (SEIA[46]) or (4) recommend different TOU periods for different customers (City of San Diego[47]). These parties fail to understand the implications of incorrectly-defined TOU periods, i.e., an on-peak period that fails to accurately capture the high-cost hours. Incorrectly-defined TOU periods - whether this be through grandfathering of TOU periods that maintain outdated "specialty" TOU periods that are different for different customers, or no change or limited change to current TOU periods - will have the same result of failing to provide customers with TOU rates that accurately reflect their actual cost-of-service, thereby providing customers with inadequate price signals to incent low-cost behavior and less opportunity to save on their bills with changes in energy consumption as already discussed in my direct testimony.

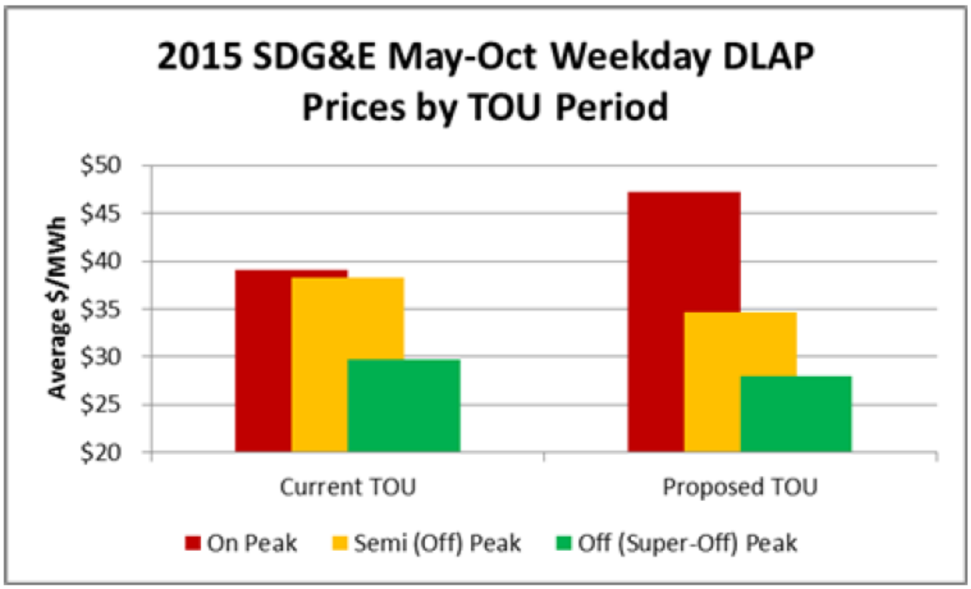
Chart 1 below presents the average 2015 SDG&E summer default load aggregation point ("DLAP") prices[48] under SDG&E's current TOU summer period (May-October), which results in an on-peak period that has an average price with almost the same price as the semi-peak

---

41 Water Districts, Witness Arant, page 3, lines 9-14.
42 CALSEIA Direct Testimony, Witness Weinberg, page 12, lines 13-15.
43 Schools Direct Testimony, Witness House, page 6.
44 SEIA Direct Testimony, Witness Beach, page 42, lines 7-16.
45 CSD Direct Testimony, Witness Monsen, page 15, lines 13-16.
46 SEIA Direct Testimony, Witness Beach, page 7, line 1.
47 CSD, Witness Monsen, page 13, line 24 – page 14, line 13.
48 Data provided in direct testimony workpapers of Robert Anderson.

period. In addition, Chart 1 shows the average 2015 SDG&E summer DLAP prices under SDG&E's proposed TOU periods, which results in high-priced hours being grouped together and consequently bigger rate differentials between on-peak, off-peak and super off-peak, providing customers price signals that create a greater opportunity for them to save on their bills through energy efficiency improvements and discretionary load-shifting.

CHART 1: COMPARISON OF AVERAGE SUMMER DLAP PRICE UNDER CURRENT AND PROPOSED TOU PERIODS



Some parties, such as ORA[49] and the Schools,[50] offer positions on how long TOU periods should remain in place. While SDG&E agrees that the Commission should strive for TOU periods that are appropriate for at least 5 years, there should continue to be flexibility to change TOU periods sooner if there is a need to do so. Absent legislative or regulatory guidance and requirements, the question of when to change TOU periods should focus on changes in system needs and corresponding changes in costs. While a preset timing, such as 5 years, may

[49] ORA Direct Testimony, Witness Chan, page 7-8, lines 12-13.
[50] Schools Direct Testimony, Witness House, page 6.

provide some benefit from the predictability of a TOU period's "life cycle," preset timing may not be able to keep pace with changes in cost-of-service in this evolving industry climate. When determining TOU periods, the focus should be on cost-of-service – otherwise stale TOU periods can shift costs between customers and increase system costs when customer incentives don't align with system needs. If the focus is not on system needs and cost-of-service, stale TOU periods can result in cost shifts between customers, wrong incentives as to when to consume electricity, exacerbation of ramping needs and higher overall system costs. Some of these issues also are pending in a general sense before the Commission in Rulemaking ("R.") 15-12-012. While SDG&E seeks the adoption of updated TOU periods in this proceeding, further TOU-related issues, such as overarching principles on how long TOU periods should be in place, may arise in the context of this rulemaking.

B. Definition of Super Off-Peak Period

Parties, such as ORA, SEIA and Farm Bureau, propose modifications to SDG&E's proposed super off-peak period. ORA proposes a two-period TOU, which would eliminate SDG&E's proposed super off-peak period.[51] Farm Bureau proposes a much broader super off-peak period of 12 a.m. to 2 p.m. on weekdays and 12 a.m. to 4 p.m. on weekends and holidays.[52] SEIA proposes a super-off peak period that is generally the same as SDG&E's current off-peak period, which begins at 10 p.m., and would be applied to weekends as well as weekdays.[53]

In SDG&E's 2015 Rate Design Window ("RDW") proceeding, the Commission stated in D.15-08-040 that historical data should be relied on to determine new TOU periods and the TOU

---

[51] ORA Direct Testimony, Witness Lu, page 6-6, lines 15-17.
[52] Farm Bureau Direct Testimony, Witness Norin, page 6, line 1.
[53] SEIA Direct Testimony, Witness Beach, page 18, lines 5-19.

periods should not be adjusted unless there is a demonstrated current system need.[54] For that reason, SDG&E has provided historical data to support its TOU proposal. Farm Bureau analyzes 2016 and 2021 forecasted data to support extending the super-off peak period into the afternoon. However, looking at the 2015 historical prices and net loads presented in the testimony of Robert Anderson, it is clear that the most recent historical data does not support Farm Bureau's proposal for 6 a.m. to 2 p.m. on weekdays to be considered super-off peak. In addition, SDG&E also believes that the super off-peak period should not encourage consumption at times when distribution circuits may be peaking, which may lead to a significant number of potential circuit overloads and the need to build added infrastructure. As such, SDG&E recommends the Commission reject Farm Bureau's proposal for an extended super-off peak on weekdays.

SEIA largely supports SDG&E's weekday super-off peak proposal, but recommends starting the super off-peak period at 10 p.m. instead of 12 a.m. SEIA proposes to "start the super-off-peak period at 10 p.m. in order to make it more convenient for customers to initiate night-time use of electricity."[55] This results in a super-off peak period no different than SDG&E's current off-peak periods of 10 p.m. to 6 a.m. on weekdays. The data, presented in the testimony of Mr. Anderson, supports the 10 p.m. - 12 a.m. period being off-peak instead of super off-peak because of higher prices and net loads during these hours than during the period of 12 a.m. – 6 a.m. SEIA provides no support for its statement that 10 p.m. is "more convenient" for customers to initiate night-time use of electricity than 12 a.m. While SDG&E agrees that customer understandability and acceptance are important considerations, these considerations also must be balanced with the need to provide customers with accurate price signals. SEIA's proposal fails to recognize the purpose of TOU pricing, which is to provide customers with price

---

[54] D.15-08-040, Conclusion of Law 2, page 37.
[55] SEIA Direct Testimony, Witness Beach, page 18, lines 7-8.

signals that reflect the different cost of providing service during different times of the day. As such, SDG&E recommends that the Commission reject SEIA's proposal to start the super-off peak period at 10 p.m.

Regarding the question of a two-period TOU rate structure, while SDG&E does not support a two-period TOU rate as the default rate for Small Commercial customers, SDG&E finds merit in creating an optional two-period TOU rate for these customers. This would be similar to what is currently being offered as SDG&E's Residential TOU Pilot Rates,[56] which include a simpler two-period (on-peak and off-peak only) option with the same on-peak period of 4 p.m. to 9 p.m. as the more cost-based three-period TOU rate, and the off-peak period defined as all other hours. While SDG&E believes there is the need for a single foundational set of TOU periods for all customers, SDG&E also supports the concept of providing differing TOU rate options for various customers and customer classes. For example, smaller customers (i.e., Residential and Small Commercial customers) may value an optional rate with fewer TOU periods, (i.e., a two-period TOU rather than a three-period TOU where the on-peak period is the same every day). This option could provide a different experience for customers, while still providing consistent on-peak price signals to all customers in order to achieve a reduction in customer usage during the afternoon ramp. Conversely, customers with greater ability to respond to price signals (including those with energy storage or electric vehicles) may prefer more complex rates based on multiple TOU periods with sharper TOU price signals. However, regardless of their differences in TOU price differentials and pricing periods, each of these rate options must be consistent with a single foundational set of TOU periods that are based on system needs and associated costs (i.e., all TOU period proposals should identify the same high

---

[56] SDG&E's Schedule TOU-DR-E2.

cost hours). Specifically, SDG&E's high cost hours for commodity procurement do not vary by customer class or customer type. As such, SDG&E proposes the introduction of a two-period optional TOU period rate for Small Commercial as well as Small Agricultural customers that would have the same on-peak period of 4 p.m. to 9 p.m. with an off-peak period defined as all other hours. This two-period rate option would have the following TOU period definition:

Year Round	
On-Peak	4 p.m. – 9 p.m. weekdays, weekends, & holidays
Off-Peak	12 a.m. – 4 p.m. weekdays, weekends, & holidays
	9 p.m. – 12 a.m. weekdays, weekends, & holidays

In addition, this optional two-period rate will provide an option to customers to address the concerns raised by ORA for flatter summer TOU rates,[57] since the two-period rate will have flatter summer differentials between the on-peak and off-peak rate than the summer differential between the on-peak and super-off peak rate under the three-period default rate. The rates associated with the two-period TOU rate options are presented in the rebuttal testimony of Mr. Swartz.

C. Seasonal Definition

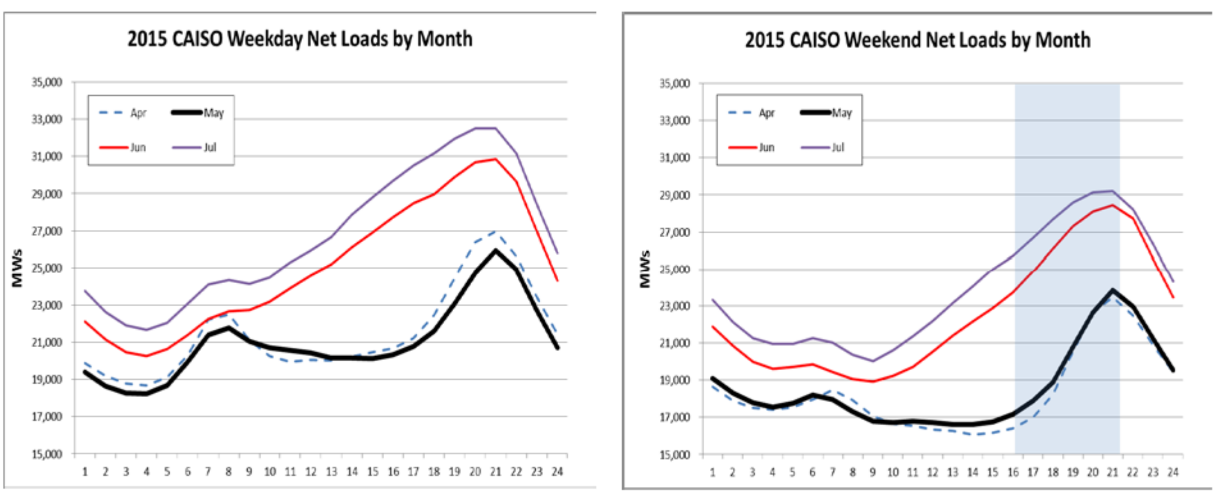
SDG&E's proposal to change TOU periods did not include a proposal to change SDG&E's current seasonal definition. Currently, SDG&E's definition of seasons consists of a 6-month summer season from May through October and a 6-month winter season from November to April. ORA's TOU period proposal included a change to SDG&E's seasonal definitions to a 4-month summer season defined as July to October and an 8-month winter

[57] ORA Direct Testimony, Witness Chau, pages 8-10 to 8-13.

season defined as November to June.[58] While SDG&E did not propose a change in the seasonal definition in its direct testimony, it is amenable to shifting May from summer to winter but recommends the Commission reject ORA's proposal to change June to a winter month. While there are occasionally some hot days in late May, the forecast data and historical price data supports ORA's proposal to shift May from a summer to winter month. Making this change will increase rate differentials between summer and winter rates and between on-peak and off-peak rates in the summer largely due to the fact that the recovery of marginal generation capacity costs are spread over fewer months.

Further information regarding SDG&E's key cost parameters for current summer and winter months is provided in the three charts below: California Independent System Operator ("CAISO") net load (Chart 2), SDG&E net load (Chart 3) and historic SDG&E DLAP prices for 2015 and 2016 (Chart 4). The examination of this data in Charts 2 and 3 shows that May has net loads similar to the current winter month of April.

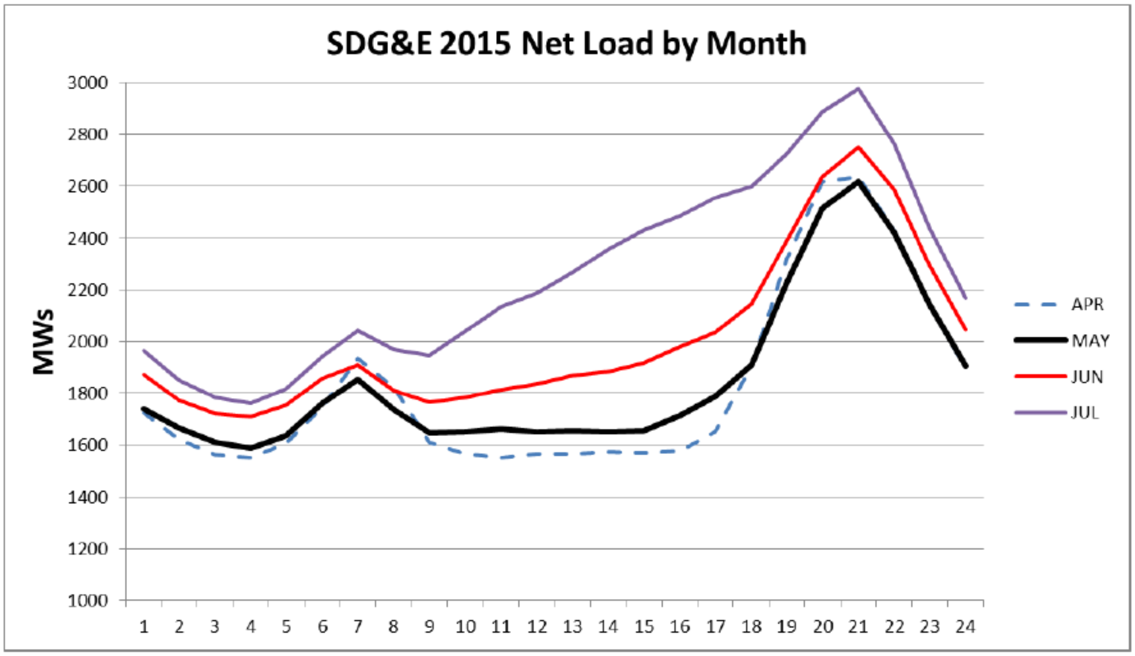
CHART 2: COMPARISON OF 2015 CAISO AVERAGE MONTHLY NET LOAD BY MONTH AND BY WEEKDAY AND WEEKEND



---

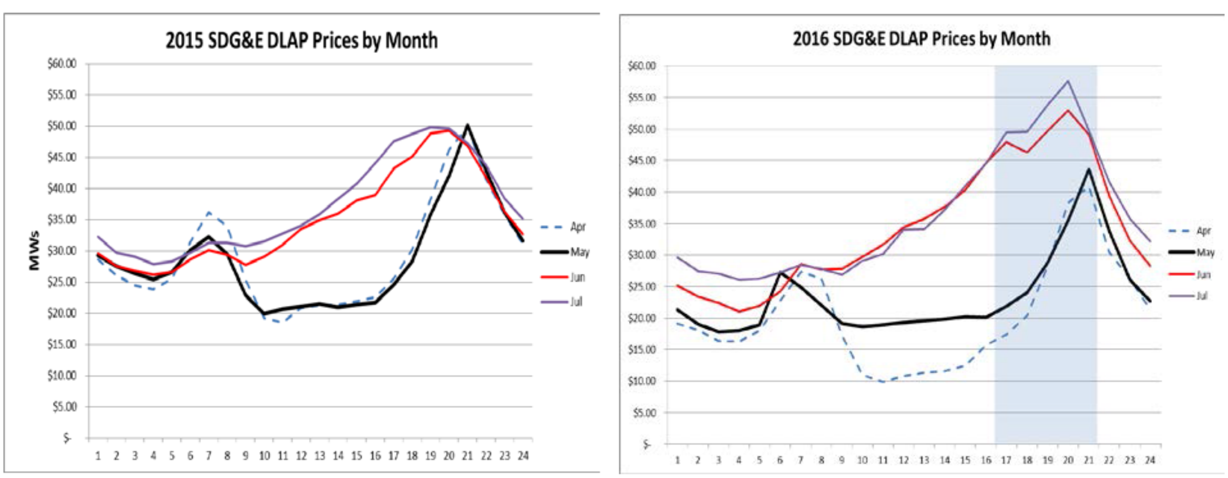
58 ORA Direct Testimony, Witness Lu, page 6-1, lines 17-18.

CHART 3: COMPARISON OF 2015 SDG&E AVERAGE MONTHLY NET LOAD BY MONTH



The average DLAP prices in Chart 4 also indicate that May looks more like April, a current winter month, than June and July, current summer months.

CHART 4: COMPARISON OF 2015 AND 2016 SDG&E AVERAGE DLAP PRICES FOR APRIL THROUGH JULY



Further, as set forth in the rebuttal workpapers of Mr. Shaughnessy, none of the top 100 hours of loss of load expectation occur in May. In addition, in Chart 2 and Chart 4, June is far more like July than May or April. As such, SDG&E recommends the Commission approve ORA's proposal to move May to a winter month but reject ORA's proposal to move June to a winter month and instead continue to maintain June as a summer month.

D. Weekends and Holidays

SDG&E's proposed TOU periods include a change to the TOU period definitions applied to weekends and holidays. SDG&E's current TOU periods consist of a three-period TOU for weekdays and a single off-peak period for weekends and holidays. SEIA[59] and Farm Bureau[60] both recognize the need for an on-peak period on the weekend, but ORA argues that the on-peak period should only be on weekdays, not weekends.[61] Notwithstanding this, ORA's testimony states:

> *SDG&E's proposed TOU peak period of 4 PM to 9 PM for all hours of the year, including weekdays and weekends/holidays, is not unreasonable, since even though marginal costs are lower during the weekend peak hours, there still remains a difference between the 4 PM to 9 PM marginal costs (higher) and the rest-of-day marginal costs during weekend periods (lower). (Page 4-3)*

---

59 SEIA Direct Testimony, Witness Beach, page 6, line 1.
60 Farm Bureau Direct Testimony, Witness Charles, page 5, lines 8-9.
61 ORA Direct Testimony, Witness Lu, page 6-6, lines 5-7.

ORA's technical analysis fully supports an on-peak period of 4 p.m. to 9 p.m. on weekends as the marginal energy prices show substantial ramping on weekends and in the summer and a significant portion of the loss of load expectation occurs on weekends.[62]

ORA suggests that customer acceptance should override their technical analysis: "ORA hopes that making weekend hour off-peak will make the behavioral shift of responding to new TOU hours easier for Residential customers." [63] There is no support for ORA's assertion, which ignores its own technical analysis for an on-peak period of 4 p.m. to 9 p.m. on weekends. In recognizing the potential impact the introduction of a weekend on-peak period may have for Residential customers, SDG&E's TOU proposal includes extending the super-off peak period by 8 hours for weekends and holidays - from 12 midnight to 6 a.m. on weekdays to 12 midnight to 2 p.m. on weekends - providing a low-priced period for flexible loads while maintaining TOU periods consistent with system needs.

The following historical data supports SDG&E's proposal for the on-peak period to be 4 p.m. to 9 p.m. on both weekdays and weekends. The occurrence of highest prices, the afternoon ramp, and largest net loads during the 4 p.m. to 9 p.m. period clearly exists on the weekends as well as weekdays. SDG&E requests that the Commission reject ORA's proposal limiting on-peak periods to just weekdays and adopt SDG&E's proposal for a 4 p.m. to 9 p.m. on-peak period on all days, including weekends and holidays.

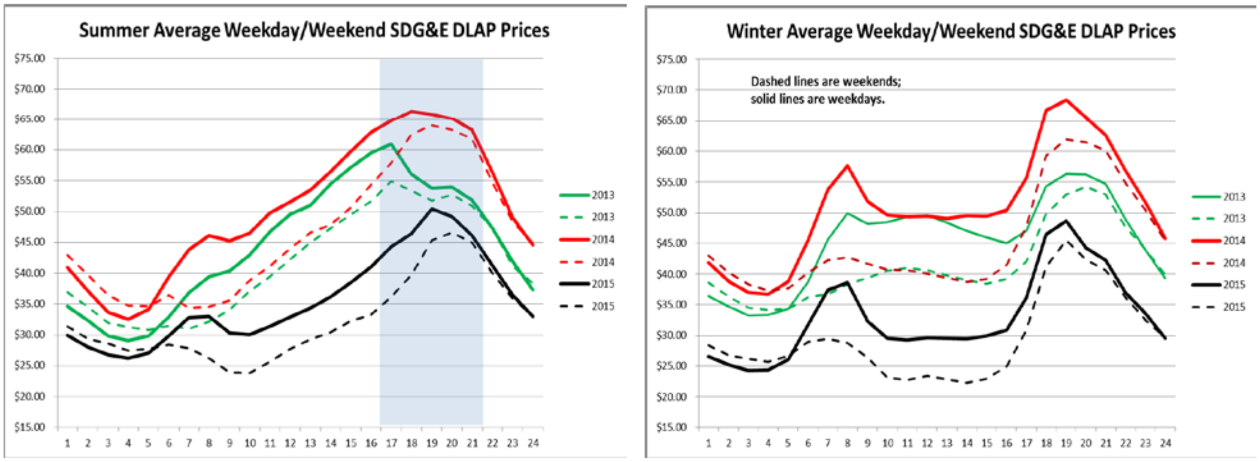
---

[62] ORA workpapers show 60.2% of the capacity allocation is in the 4 p.m. to 9 p.m. time period with 44.1% on weekdays, indicating 16.1% is on weekends. (16.1% divided by 60.2% = 26.7%).

[63] ORA Direct Testimony, page v, lines 5-7.

CHART 5: HISTORICAL SDG&E DLAP PRICES

BY YEAR BY WEEKDAY/WEEKEND AND SEASON



V. COST-BASED RATES

In this proceeding, SDG&E proposes a gradual movement towards cost-based rates for its non-Residential customers.[64] Utility rates recover the costs of services related to commodity resources, distribution resources, transmission resources and public purpose programs. Under SDG&E's current effective rates, commodity services represent approximately 50% of total costs recovered, distribution represents approximately 30%, transmission covers 10% and the remaining 10% represents the costs of State and Commission mandate programs.

In addition to the recovery of State and Commission-mandated program costs, utility rates address the recovery of the following categories of costs to serve customers:

- **Customer Costs**: These costs are independent of a customer's energy use and are required for each interconnected customer whether or not the customer uses

[64] SDG&E Direct Testimony, Witness Swartz, Chapter 2, page CS-5, lines 9-12. As noted in the Direct Testimony of witness Swartz, Residential rates were addressed in the RROIR proceedings, and therefore not addressed here.

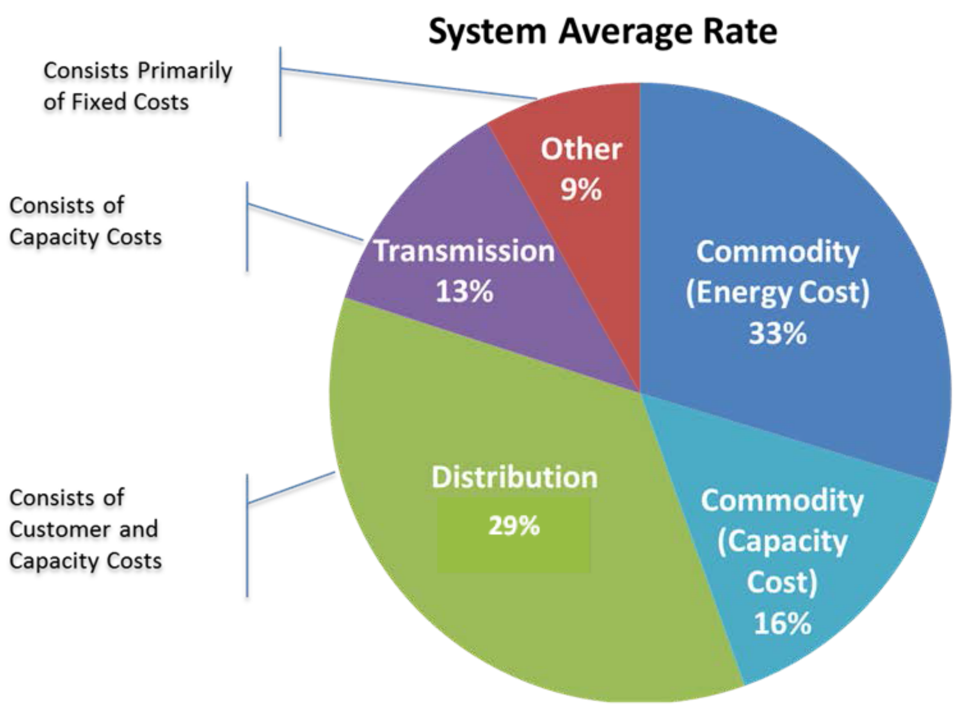
electricity; therefore, customer costs should be recovered in a fixed or monthly charge ($/month).

- **Energy Costs**: These costs are incurred on a variable basis (based on energy usage) with costs dependent on the time of delivery.
- **Capacity-related Costs**: These costs include Generation Capacity costs, Distribution Demand costs and Transmission costs.
  - ***Generation Capacity Costs*** – These costs are not incurred on the basis of energy usage, but rather on the basis of meeting net peak capacity needs of the system; therefore, system capacity costs should be recovered in a demand charge consistent with the time period in which those costs occur, which is demand at the time of net system peak when additional capacity ($/peak-kW) may be required.
  - ***Distribution Demand Costs*** – These costs are incurred independent of a customer's energy usage to reliably meet the local capacity needs of the combined maximum demand of customers served off of a given circuit.
  - ***Transmission Costs*** – These costs are incurred to meet reliability requirements, which also include (1) the need to address contingency conditions (e.g., the forced outage of one or more transmission lines that can occur at any time), (2) policy obligations (such as delivering and integrating renewable resources to meet Renewable Portfolio Standard ("RPS") requirements), (3) economics (where the economic benefits to consumers from reducing Local Capacity Requirements ("LCRs") or minimizing congestion-related costs offset the cost of the transmission upgrade) and

(4) maintenance (such as aging infrastructure replacement and where new transmission is needed to allow other transmission facilities to be removed from service for maintenance without interruption of customer load).

When reviewing the breakdown of the cost of utility services, only a small fraction of the services recovered in electric utility rates are driven by the kWh energy usage of customers. The majority of the costs to serve customers are fixed. These costs are incurred independent of customer kWh usage and are driven either by (1) the number of customers or (2) the capacity needs of customers, which result from their maximum load or demand of the customer.

CHART 6: BREAKOUT OF SYSTEM AVERAGE RATE



As noted in Chart 6 above, only Commodity costs include any costs driven by a customer's kWh energy usage. SDG&E's marginal commodity cost studies indicate approximately 67% of Commodity costs, which represent less than 50% of the system average rate, are associated with marginal energy costs, resulting in only approximately 1/3 of the total utility cost of service being related to the kWh energy usage of customers. However, over 75% of all costs recovered in rates are recovered through energy rates.

Several parties, including ORA,[65] Farm Bureau,[66] CALSEIA,[67] SEIA,[68] CALSLA[69] and CSD,[70] opposed SDG&E's proposed movement towards more cost-based rates. Farm Bureau's proposal that monthly service fee ("MSF") increases be rejected or delayed to Year 2 for the Agricultural class[71] and that non-coincident demand ("NCD") charges be delayed until the next GRC cycle[72] would result in almost no movement at all towards cost-based rates for the Agricultural class. SDG&E addresses these arguments in detail below.

A. Fixed Charges for Non-Residential Customers

Parties, such as ORA,[73] Farm Bureau,[74] SEIA,[75] CALSLA,[76] and CALSEIA,[77] oppose SDG&E's proposal to move non-Residential MSFs towards more cost-based levels. FEA's proposal for a "two-part MSF" to eliminate fixed charges for Substation customers[78] is being addressed in the rebuttal testimony of Mr. Swartz. As with all rate design changes, SDG&E's

---

65 ORA Direct Testimony, Witness Chau, page 8-5, lines 14-17.
66 Farm Bureau Direct Testimony, Witness Norin, page 35, lines 1-3.
67 CALSEIA Direct Testimony, Witness, page 12, lines 18-21.
68 SEIA Direct Testimony, Witness Beach, page 23, lines 7-8 & page 24, lines 16-18.
69 CALSLA Direct Testimony, Witness Lechowicz, page 19, lines 17-20.
70 CSD Direct Testimony, Witness Monsen, page 4, lines 24-27.
71 Farm Bureau Direct Testimony, Witness Norin, page 35, lines 1-5.
72 Farm Bureau Direct Testimony, Witness Norin, page 36, lines 6-8.
73 ORA Direct Testimony, Witness Chau, page 8-5, lines 14-17.
74 Farm Bureau Direct Testimony, Witness Norin, page 35, lines 1-3.
75 SEIA Direct Testimony, Witness Beach, page 23, lines 7-8.
76 CALSLA Direct Testimony, Witness Lechowicz, page 19, lines 17-21.
77 CALSEIA Direct Testimony, Witness Weinberg, page 12, lines 18-21.
78 "It is my recommendation that the BSF [basic service fee] for these customers be in two parts. (1) The regular customer charge applicable to regular primary customers and regular secondary customers. (2) A non-coincident demand charge equal to the EPMC value of substation demand costs, which is $2.40 per kW, per month." – FEA Direct Testimony, Witness Brubaker, page. 16, lines 16-19.

proposal to increase MSFs will result in both winners and losers. Non-Residential MSFs that are not cost-based (MSFs that recover less than 100% of customer costs) result in overinflated demand charges (in the case of M/L C&I customers) or overinflated energy rates (in the case of Small Commercial customers). As such, the structure of current rates results in high-demand or high-energy usage customers paying more than their cost-of-service while low-demand and low-usage customers pay less than their cost-of-service. SDG&E's proposal to move MSFs closer to cost-based levels will result in reductions to demand charges or energy rates and move to a more equitable recovery of costs from customers. By reducing the recovery of customer-related distribution costs from demand charges and energy rates, customers will have more accurate prices signals for the investment in DER technologies in a manner that minimizes cost shifts to other customers. In addition, parties fail to recognize that some customers benefit under such a rate structure. SDG&E's proposed cost-based rate options include fully-loaded fixed and demand charges for M/L C&I customers and a more cost-based rate option for Small Commercial customers with a greater fixed charge for the recovery of all distribution costs. Under these more cost-based options, (1) over 30% of M/L C&I customers would benefit under a fully cost-based rate option compared to SDG&E's current standard M/L C&I rate schedule AL-TOU, (2) 20% of Small Commercial customers would benefit under a more cost-based rate option without any change in usage compared to SDG&E's current standard Small Commercial rate schedule TOU-A and (3) just over 25% of medium and large Agricultural customers on SDG&E's standard Agricultural rate schedule TOU-PA, greater than 20 kW, would benefit on SDG&E's proposed cost-based rate option.[79] As such, the Commission should reject intervenor

[79] Attachment K of Rebuttal Testimony, Christopher Swartz.

arguments and approve SDG&E's proposal to move non-Residential MSFs towards more cost-based levels.

B. Demand Charges for Medium and Large Non-Residential Customers

1. Demand Charges for the Recovery of Distribution Costs

SDG&E proposes to change the current recovery of distribution costs not recovered through a fixed charge to move towards greater recovery through a NCD charge, ultimately transitioning to 100% recovery through a NCD charge. FEA's witness Mr. Brubaker supports SDG&E's proposal and states that "given the nature of these costs, and the fact that they are incurred in order to serve customer and subgroup maximum demands, I believe that SDG&E's proposal in this regard is generally reasonable."[80] Parties such as SEIA and the City of San Diego oppose SDG&E's proposal to move the current recovery of distribution demand costs more towards non-coincident demand charge. The City of San Diego argues for the reduction or elimination of the current NCD or the allocation of substation costs based on seasonal peak demand.[81] SEIA asserts three reasons for opposing SDG&E's NCD proposal: (1) SDG&E's proposal is not cost-based because the maximum demands of individual customers at best drive only a portion of SDG&E's distribution costs, (2) the data and related metrics for on-peak demands on SDG&E's distribution system show that a significant portion of SDG&E's distribution costs are time-dependent and are driven by customer loads during the on-peak period, not by customer's individual maximum demands whenever those occur and that (3) SDG&E's proposal is inconsistent with how SDG&E calculates marginal distribution costs. I will address SEIA's first two claims; Mr. Saxe will address SEIA's third claim.[82] [83]

---

[80] FEA Direct Testimony, Witness Brubaker, page 21, lines 14-16.
[81] CSD Direct Testimony, Witness Monsen, page 34, lines 20-22.
[82] SDG&E Rebuttal Testimony of William G. Saxe, Chapter 5.

While SDG&E agrees with SEIA that a portion of distribution resources are peak driven, this peak is a circuit peak, unlike the system/commodity-related peak that drives the definition of TOU periods. As stated in John Baranowski's direct testimony,[84] SDG&E's distribution system is designed to meet individual customer service requirements and not designed with coincident system peak demand in mind. The goal of the distribution planning department is to ensure that each distribution circuit and substation has adequate capacity to serve its local peak demand, regardless of when it occurs. Designing the distribution system based on customer load coinciding with system peaks could erode the safe and reliable operation of the distribution system. Because SDG&E is ultimately responsible for providing safe and reliable service, SDG&E does not base its distribution system design on coincident system peak, but rather on the peak of each area being served by the distribution system. Therefore, distribution marginal costs are driven by the highest demand level of a customer, circuit or substation that would cause new investment in distribution infrastructure to provide the necessary capacity. The highest demand of a given customer, circuit or substation may occur at completely different times throughout the day, and thus won't be appropriately captured in a single TOU period, especially one based on the system peak. A single TOU period will necessarily result in inaccurate TOU periods for portions of the distribution system. To accurately capture that diversity through a TOU rate structure would require different TOU period definitions by circuit and substation, which would create too many challenges for customer understandability.

Not only do different circuits peak at different times throughout the day, but an individual circuit may experience multiple peaks throughout the year that also can occur at different hours. To capture these events in a TOU rate, the TOU windows would need to be cast broadly, both in

---

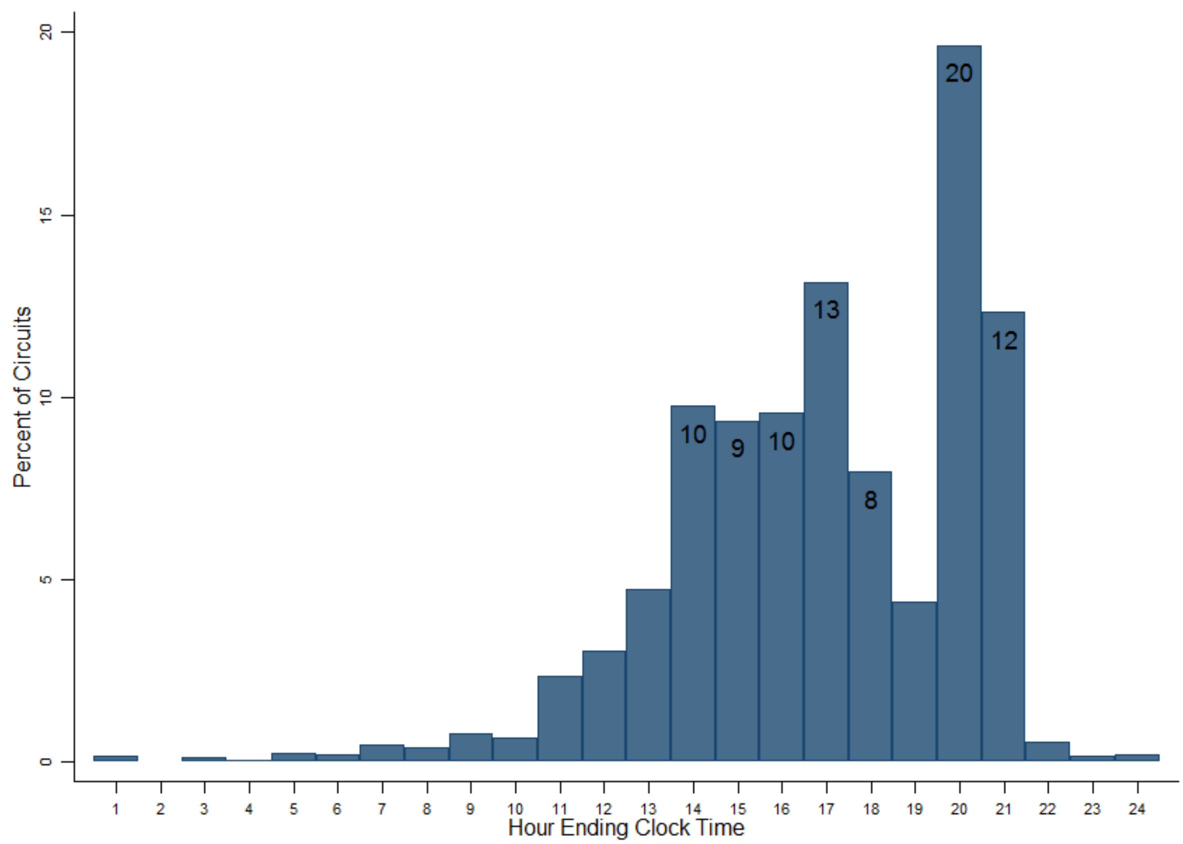
[83] SEIA Direct Testimony, Witness Beach, page 24, lines 16-18.
[84] SDG&E Direct Testimony of John Baranowski, Chapter 5.

the hours of the day and months of the year, which would dilute the price signals that are meant to elicit specific customer behavior.

When considering whether TOU pricing is appropriate for the recovery of distribution resources, the process should begin with an examination of the hours in which distribution circuits peak.

Chart 7, below, presents the wide range of times during which distribution circuits peak.

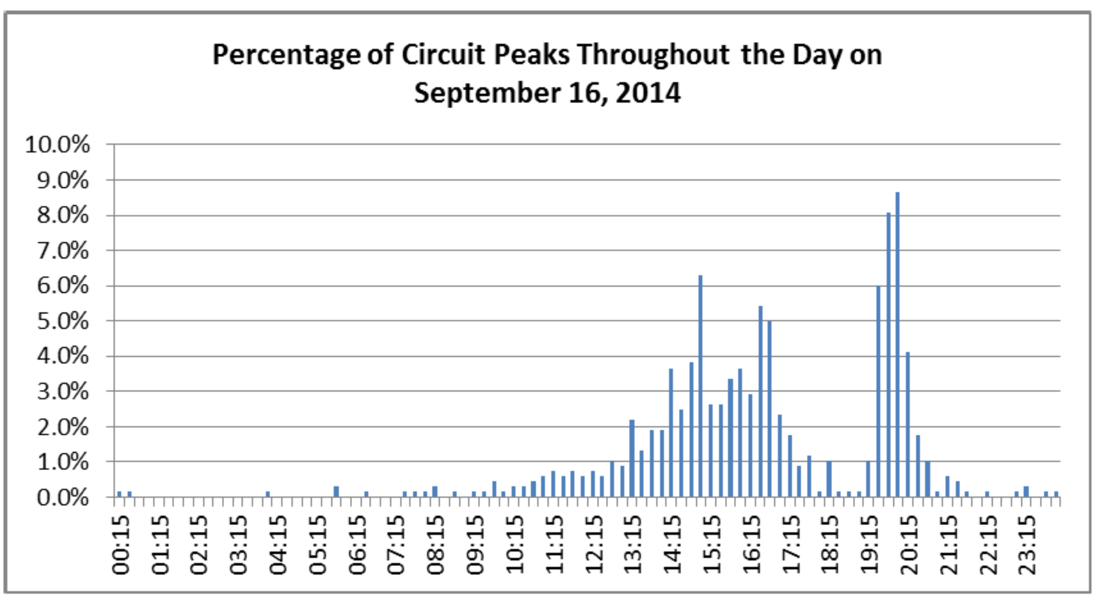
CHART 7: DISTRIBUTION OF 2014-2015 SDG&E CIRCUIT PEAKS BY HOUR ENDING



As can be seen in Chart 7 above, distribution circuits peak over a wide range of times that do not necessarily coincide with times of system peak capacity need. This is because the drivers behind distribution costs differ from those behind system and commodity costs in that the cost drivers for distribution demand focus more locally.

TOU pricing is intended to capture differences in high-cost hours that occur on more of an "everyday" basis due to more "typical" cost differences across the days within a given season. This then warrants further analysis of the occurrence of system peak with circuit peak hours across different days. SDG&E's all-time system peak occurred on September 16, 2014 at 3:52 p.m. However, in reviewing the individual circuit peaks on that day, it is clear that those circuit peaks occurred at all hours, not necessarily coincident with the system peak. As previously presented in the direct testimony of Mr. Baranowski[85] and provided again below in Chart 8, out of 682 circuits, 6% peaked between midnight and noon that day, 36% peaked between noon and 4 p.m., 55% peaked from 4 p.m. to 9 p.m., and 2% peaked between 9 p.m. and midnight.

CHART 8: DISTRIBUTION OF CIRCUIT PEAKS ON ALL-TIME PEAK DAY



[85] SDG&E Direct Testimony of John Baranowski, Chapter 5.

This distribution of circuit peaks changes when comparing the all-time peak day to a more typical summer day. SDG&E compared the number of circuits that peaked during the same time period on September 16, 2014 with a more typical summer day, which occurred one week prior to the system peak day on September 9, 2014. This comparison showed that only 55% of the same circuits peaked on both days between 11 a.m. to 6 p.m. (SDG&E's current on-peak period), and only 45% of the same circuits peaked on both days between 4 p.m. to 9 p.m. (SDG&E's proposed on-peak period). This variability from day-to-day of the timing of circuit peaks raises additional concerns about the appropriateness of TOU pricing for distribution demand resources.

To accurately capture the cost drivers of distribution circuits would require circuit-specific TOU periods distinct from TOU period definitions intended to capture system peak. This would require a different definition of high-cost hours and different definitions of seasons. There also may be a need to consider the appropriate frequency to change TOU period definitions to reflect changes in high-cost hours. Circuit-specific TOU periods would be expected to change more frequently given their more local nature.

If the definitions of TOU periods are wrong, then the price signals provided to customers will not accurately reflect the cost of providing commodity services. Applying TOU pricing that accurately reflects the cost drivers for distribution demand-related costs would require unique circuit-specific TOU periods. This would be in addition to system-based TOU periods for commodity services. Issues related to customer confusion that unique circuit-specific TOU period definitions might cause require further exploration of appropriate pricing for distribution demand-related costs. This exploration also should include the examination and comparison of alternatives to TOU pricing, such as NCD charges (which incent customers to levelize loads) or more event-based alternatives, such as critical peak pricing ("CPP") at the circuit level, as presented in SDG&E's Vehicle Grid Integration ("VGI") pilot program rate,[86] and a discussion of the tradeoffs between these various approaches. In short, developing appropriate TOU pricing for distribution demand-related costs is currently understudied.

As noted above, an alternative structure to accurately capture the diversity of the distribution system would be to introduce a dynamic hourly rate that has the flexibility to capture the top circuit peak hours, such as SDG&E's VGI rate[87] and SDG&E's Residential TOU Pilot Rate 3.[88] While such a structure would result in rates that reflect accurate price signals and meets the Cost of Service Residential Design Principles ("RDPs") articulated in the RROIR,[89] such an option creates challenges for the Customer Education and Customer Acceptance RDPs.

Given the complexity of a dynamic hourly rate structure, a NCD charge can provide a next-best solution to encourage customers to reduce their peak demand, which in the aggregate will have the effect of reducing circuit and substation demand.

---

86 Application 14-04-014; D.16-01-045, Direct Testimony of Cynthia Fang, Chapter 3.

87 Approved January 28, 2016 by D.16-01-045 in A.14-04-014.

88 Approved March 18, 2016 by Resolution E-4769, pursuant to D.15-07-001 in R.12-06-013.

89 Attachment A to November 26, 2012 Scoping Memo and Ruling in R.12-06-013, Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations ("RROIR"):

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
2. Rates should be based on marginal cost;
3. Rates should be based on cost-causation principles;
4. Rates should encourage conservation and energy efficiency;
5. Rates should encourage reduction of both coincident and non-coincident peak demand;
6. Rates should be stable and understandable and provide stability, simplicity and customer choice;
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
8. Incentives should be explicit and transparent;
9. Rates should encourage economically efficient decision-making; and
10. Transitions to the new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

Thus, the distribution costs that utilities incur to provide service to customers may be best measured on the basis of a customer's individual maximum demand, distinct from demand at the time of peak system capacity need. The distribution system (which includes distribution demand-related costs, including substations, circuits, feeders, and applicable operations & maintenance ("O&M") costs) is built to meet local, as opposed to system, demand to ensure reliable service to customers at the local neighborhood level. The planning criteria for distribution infrastructure are based on local load at the circuit and substation level. In other words, in order to provide reliable service to a range of distribution circuits, each of which has different levels of peak demand, the distribution system is designed to have adequate capacity to serve the combined peak demand of all customers served off of a distribution circuit, without regard to when that demand occurs (non-coincident peak).

CSD argues for the recovery of substation costs based on seasonal peak demands.[90] The costs of the distribution system consist of the following costs, beginning with the meter at the customer's home:

1) The meter, which provides the ability to measure customer's energy and load;
2) Service lines, which connect individual customers to their service final transformer;
3) The final transformer, which steps down voltage to levels that are usable and more safe;
4) Customer services, which represent costs for activities such as field services, advanced metering, billing, credit & collections, branch office, customer contact center, residential customer services, commercial & industrial services, communications and customer programs;

---

[90] CSD Direct Testimony, Witness Monsen, page 34, lines 20-22.

5) Circuits (otherwise known as Feeders and Local Distribution), which consist of the costs associated with the primary distribution system, such as switches, conductors, capacitors, line regulators, insulators, poles, vaults, conduit, fuses, etc.; and

6) Substations (where the point of conversion from transmission to distribution voltages occurs), which consist of transformers, circuit breakers, switches, insulators, bus work, control houses, system protection, etc.

While moving further up the distribution system away from the customer meter results in a greater aggregation of customer load and may bring greater alignment with system peak, it does not guarantee alignment with system peak. As such, it is expected that the aggregation of customer load that occurs from circuit to substation would result in substation load having a higher level of coincidence with system load than occurs at the circuit level; nonetheless, there would continue to be differences from the system. Even at the transmission level, not all transmission costs are peak driven as discussed in more detail below.

Circuit and substation costs make up demand-related distribution costs. Based on the distribution cost studies presented by Mr. Saxe,[91] demand-related distribution costs represent 60% of distribution costs, and substation costs represent 23% of demand-related distribution costs, or 14 % of total distribution costs. Even if it were to be determined that it would be reasonable to recover substation-related costs through a demand charge based on system peak, it would not be appropriate to recover all substation costs through a TOU charge. Substation costs, identified above as the costs associated with the point of conversion from transmission to distribution voltages, would then need to be broken out into what portion of substation costs are appropriately peak driven.

---

[91] SDG&E Rebuttal Testimony of William G. Saxe, Chapter 5.

2. Transmission

CSD[92] and SEIA[93] also included proposals to move the recovery of transmission costs to an on-peak demand charge. System peak is not the sole driver of transmission costs. Transmission costs are driven by:

- **Reliability requirements**, which also include the need to address contingency conditions (e.g., the forced outage of one or more transmission lines) that can occur at any time;
- **Policy obligations,** such as delivering and integrating renewable resources to meet RPS requirements and Greenhouse Gas ("GHG") reduction goals;
- **Economics**, where the economic benefits to consumers from reducing LCRs or minimizing congestion-related costs offset the cost of the transmission upgrade; and
- **Maintenance**, such as aging infrastructure replacement and where new transmission is needed to allow other transmission facilities to be removed from service for maintenance without interruption of customer load.

These drivers can be independent of system peak. A cost-based price signal for transmission-investment costs is some combination of peak and non-peak related charges. Further study is required to determine what the correct split is between peak and non-peak related transmission costs. It also is important to note that transmission rates are not Commission jurisdictional; as such, these issues are most appropriately addressed before the FERC.

---

[92] CSD Direct Testimony, Witness Monsen, page 33, lines 16-19.
[93] SEIA Direct Testimony, Witness Beach, page 39, lines 18-19.

3. Demand Charges for Residential

UCAN provided extensive testimony regarding the appropriateness of a demand charge for Residential customers.[94]

While SDG&E is not proposing a Residential demand charge in this proceeding, the picture painted by UCAN is incomplete and thus, SDG&E feels compelled to at least briefly address UCAN's testimony on this issue. The 2014 Rocky Mountain Institute ("RMI") paper[95] and the Arizona Public Service ("APS") Demand Charge Study[96] both paint a picture of demand charges that differs from UCAN. RMI explains that a demand charge creates an incentive to add combinations of DERs that more evenly spread use throughout the day, thereby lowering the impact and cost on the system. When a customer with a demand charge also is a net-metered customer, the demand charge is not avoided by excess generation credits, resulting in better cost recovery for the capacity required to support some DERs. A demand charge also begins to reduce intra-class cross subsidies created between customers with different load factors. These points directly refute the arguments of UCAN's witnesses Garrick F. Jones and William Perea Marcus: "The Commission should reject Residential demand charges out of hand for creating intra-class subsidies of big users, before even thinking about dealing with the rest of the problems caused by their implementation that I discussed above."[97]

In addition, the APS Demand Charge Study illustrated that 90% of customers with demand rates have saved on their summer bills. Among the 90%, 42% were small and midsized customers, directly refuting the claim that "using a maximum demand charge to collect demand

[94] UCAN Direct Testimony, Witnesses Jones and Marcus, pages 41-53.

[95] Rocky Mountain Institute, Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Energy Future, August, 2014, p. 23. Available at: http://www.rmi.org/elab_rate_design.

[96] Presentation made by APS at EUCI 2nd Annual Residential Demand Charge Summit, June 2016.

[97] Direct Testimony of Garrick Jones and William P. Marcus on behalf of Utility Consumers Action Network Page 44 CPUC Application 15-04-012.

costs will systematically overcharge small customers and undercharge larger customers on the SDG&E system."[98]

SDG&E requests that the Commission reject UCAN's unfounded arguments on this issue.

VI. OTHER POLICY ISSUES

A. Residential Rate Reform

With the exception of the introduction of a new cost-based option for Residential electric vehicle customers, SDG&E makes no new proposals in this proceeding to Residential tiered rates, which were addressed in D.15-07-001. In contrast, ORA's testimony seeks further decisions in this proceeding on issues addressed in D.15-07-001 and Resolution E-4787.[99] SDG&E asks that those comments be dismissed as out of scope.

B. Regulatory Vehicle for Sales Updates

SDG&E requests approval of the three-year sales forecast (2016, 2017 and 2018) presented in the rebuttal testimony of Mr. Schiermeyer.[100] In this proceeding, SDG&E also is requesting authorization to submit the presentation of rate impacts associated with updated annual sales prior to implementation of SDG&E's annual Consolidated advice letter filing for rates effective January 1 of each year. The Farm Bureau supports the need for additional test-year sales forecasts and agrees that these should be approved as part of this proceeding.~~,~~[101] While ORA supports SDG&E's proposal to update sales annually, ORA opposes SDG&E's

---

[98] Direct Testimony of Garrick Jones and William P. Marcus on behalf of Utility Consumers Action Network Page 49 CPUC Application 15-04-012.

[99] ORA Direct Testimony, Witness Chan, page 7-5, line 15 – page 7-6, line 6 and page 7-7, line 10 – pages7-8, line 2.

[100] SDG&E Rebuttal Testimony of Kenneth Schiermeyer, Chapter 4.

[101] Farm Bureau Direct Testimony, Witness Norin, page 22, lines 11-14.

proposed regulatory vehicle to update sales and instead proposes that sales updates be addressed in SDG&E's Energy Resource Recovery Account ("ERRA") Forecast proceeding.[102]

SDG&E has concerns with ORA's recommendation. First, SDG&E's current annual ERRA Forecast proceedings do not involve approving updated sales forecasts and a change in scope of the ERRA proceeding could create the potential to change the schedule and timing of SDG&E's ERRA Forecast proceedings. Delays in decisions in SDG&E's ERRA Forecast proceeding from a January 1 date increases the risk of commodity over/undercollections, which introduces greater potential for rate volatility to utility customers.

Sales updates have implications to rate design, including residential tiered rates,[103] and revenue allocations. Moving the approval of updated sales forecasts from SDG&E's rate design proceedings to the ERRA Forecast proceeding also likely would place a burden on parties who don't otherwise participate in SDG&E's ERRA Forecast proceedings but who have an interest in such issues. In summary, SDG&E believes that updates to test-year sales are most appropriately addressed in rate design proceedings, not SDG&E's ERRA Forecast proceeding.

C. Proposed Discount Program for Public Schools K-12

Although SDG&E has attempted to work with the San Diego Public Schools during the course of this proceeding, no mutually agreeable solution has been achieved to date.[104] Nonetheless, SDG&E continues to stand by its commitment to work with the schools and, as such, proposes a Public Schools Discount Program for Public Schools grades K-12 in SDG&E's

---

[102] ORA Direct Testimony, Witness Duran, page 5-1, lines 19-23.

[103] For example, at the May 25 Progress on Residential Rate Reform meeting, SDG&E presented the implications of alternative scenarios of glidepath rules on Residential tiered rates under a scenario of a 4% reduction in annual sales, noting that the impact to tiers can vary depending on how the sales decline is reflected in changes to tiered usage.

[104] See, e.g., Tr. page 100, line 3 – page 101, line 8 from the March 21, 2016 prehearing conference in this proceeding.

service territory that would provide a 10% line item discount off of their monthly electric bills. This discount would apply for the term of this GRC Phase 2 and would remain in effect until the implementation of SDG&E's next GRC Phase 2 proceeding, the 2019 GRC Phase 2.

This discount would be in addition to the benefits the Schools would achieve from the adoption of SDG&E's other proposals in this proceeding. SDG&E's proposals in this proceeding, specifically the TOU period proposal and the proposed revenue allocations, result overall in benefits to the public schools K-12 represented by the members of the San Diego Public Schools.[105] While the Schools' various accounts cross several customer classes, the vast majority (70%) of the school accounts are part of the M/L C&I class, which would see benefits due to the reduction in allocated revenues under SDG&E's proposal. These accounts make up 98% of the Schools' accounts sales and 98% of electric-billed revenues.[106] Although SDG&E's proposed TOU periods result in providing the Schools with fewer operational hours occurring in the proposed on-peak period of 4 p.m. to 9 p.m. (22.9% of the total kWh for the Schools' accounts occur during the current on-peak period whereas only 18.6% of the total kWh would

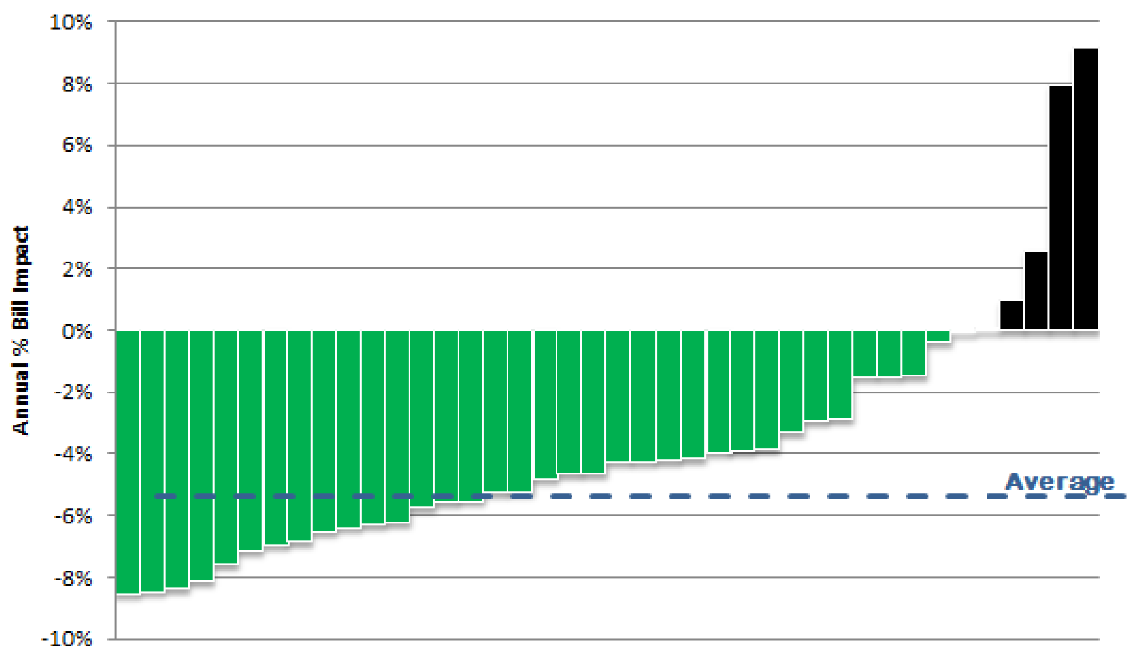
[105] The members of the San Diego Public Schools are Alpine School District, Bonsall Unified School District, Borrego Springs Unified School District, Cajon Valley Union School District, Cardiff School District, Carlsbad Unified School District, Chula Vista Elementary School District, Coronado Unified School District, Dehesa School District, Del Mar Union School District, Encinitas Union School District, Escondido Union School District, Escondido Union High School District, Fallbrook Union Elementary School District, Fallbrook Union High School District, Grossmont Union High School District, Jamul-Dulzura Union School District, Julian Union School District, Julian Union High School District, La Mesa-Spring Valley School District, Lakeside Union School District, Lemon Grove School District, Mountain Empire Unified School District, National School District, Oceanside Unified School District, Poway Unified School District, Ramona Unified School District, San Diego County Office of Education, San Diego Unified School District, San Dieguito Union High School District, San Marcos Unified School District, San Pasqual Union School District, San Ysidro School District, Santee School District, Solana Beach School District, South Bay Union School District, Spencer Valley Elementary School District, Sweetwater Union High School District, Valley Center-Pauma Unified School District, Vista Unified School District and Warner Unified School District. SDG&E did not include the San Diego Country Office of Education in the bill impact data.

[106] Based on current rates effective 8-1-2016 and historic usage from June 2015-May 2016.

occur during SDG&E's proposed on-peak period, a reduction of almost 20%.), overall, 78% of the Schools' accounts would benefit under SDG&E's proposals in this proceeding.[107]

The majority of the 40 individual school districts analyzed showed annual bill benefits from SDG&E's TOU proposal. At the district level, 35 school districts (88%) showed estimated bill reductions resulting from SDG&E's proposals (as shown in Figure 1). Collectively, the 40 identified school districts showed an estimated bill reduction of approximately 4.5% from SDG&E's proposals.

Figure 1 - Bill Impacts by District



[107] SDG&E's analysis covered 1,255 accounts for public schools, grades Kindergarten through twelfth (K-12), and represented 40 school districts. The analysis examined illustrative bill impacts associated with SDG&E's proposals reflected in the rates presented in the rebuttal testimony of SDG&E witness Swartz. The illustrative bill impacts are based on historical data from June 2015-May 2016 for accounts that had a complete 12 months of historical smart meter data, assume no change in usage, and reflect the change in rates and TOU periods from SDG&E's proposal in this proceeding only. They do not include items such as taxes, franchise fees, etc.

D. Implementation Timing

ORA recommends that SDG&E's GRC Phase 2 be implemented at the same time as the RROIR glidepath implementation, stating that rate changes should be consolidated to reduce customer confusion[108] within the first 90 days of 2017.[109] While SDG&E agrees in principle with consolidating rate changes to minimize the number of rate changes for customers, adequate time between decision and implementation for the necessary education and outreach is critical to ensure that our customers are adequately informed regarding the changes in TOU periods. For this reason, an early winter implementation would be the preferred timing for introducing a change in TOU periods given that the change to winter-TOU periods is smaller than the proposed change to summer-TOU periods; an early winter-implementation also would allow for more time for education and outreach prior to summer. SDG&E's proposed change to the winter on-peak period is small (moving from 5 p.m. to 8 p.m. weekdays to 4 p.m. to 9 p.m. every day), as compared to summer (which would be moving from 11 a.m. to 6 p.m. weekdays to 4 p.m. to 9 p.m. every day). Given that this implementation is anticipated to address the change of TOU periods, the implementation date also should allow sufficient time for customer education and outreach ahead of summer months, where TOU period differences and differentials are greater, and therefore have the potential to have the biggest impact on customers. However, this must be balanced with the need to get the correct TOU periods in place for customers in a timely manner. As such, SDG&E anticipates that 60-90 days from a final decision to the beginning of summer (i.e., 2-3 months prior to summer) is needed for education and outreach to impacted customers of the TOU period changes.

---

[108] ORA Direct Testimony, Witness Chan, page 7-1, line 15.
[109] D. 15-07-001, page 304.

VII. SUMMARY AND CONCLUSION

The following summarizes SDG&E recommendations in response to parties' direct testimony on policy and revenue allocation issues related to SDG&E's electric rate design proposals.

- The Commission should approve SDG&E's proposed revenue allocation proposals for Distribution, Commodity, PPP, CTC and LGC, including a 3-year transition for Distribution and Commodity.
- The Commission should approve updated revenue allocations for CSI and SGIP to account for the movement of Schedule PA-T-1 into the Agricultural class, and SDG&E's proposal to move these two programs to the PPP rate component and be charged to customers on the basis of delivered energy consistent with existing PPP cost components.
- The Commission should approve SDG&E's proposed TOU periods and SDG&E's proposed seasonal definitions, which include the move of May to a winter month.
- The Commission should approve SDG&E's proposal for an optional two-period TOU rate for both Small Commercial and Small Agricultural customers.
- The Commission should approve SDG&E's proposals for movement towards cost-based rates through increases to MSFs or NCD charges for non-residential customers.
- The Commission should dismiss as out of scope ORA's requests for decisions on Residential Rate Reform issues addressed in D.15-07-001 and Resolution E-4784.
- The Commission should approve SDG&E's 2016, 2017 and 2018 sales forecast as part of this proceeding.

This concludes my rebuttal testimony.