Docket:	:	A.15-04-012
Exhibit Number	:	ORA-1
Commissioner	:	Mike Florio
Admin. Law Judge	:	Jeanne McKinney
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OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Testimony on San Diego Gas and Electric's 2016 General Rate Case Phase 2

San Francisco, California
June 3, 2016

MEMORANDUM

This report was prepared by the Office of Ratepayer Advocates ("ORA") of the California Public Utilities Commission ("Commission") in Application ("A.") 15-04-012. In this docket, the applicant proposes to update marginal costs and the cost allocation. SDG&E also proposes major changes to the time of use ("TOU") periods and proposes a number of changes to the design of electric rates. In this report, ORA presents its analysis on marginal costs, the cost allocation, revised TOU periods, and makes recommendations on residential and small commercial rates.

Aaron Lu and Dexter Khoury served as ORA's project coordinators in this review, and are responsible for the overall coordination in the preparation of this report. Mike Campbell (Branch Program Manager) and Lee-Whei Tan (Project and Program Supervisor) oversaw this project and the review of this report. ORA's witnesses' prepared qualifications and testimony are contained in the Appendix of this report.

List of ORA Witnesses and Respective Chapters

Chapter Number	Description	Witness
-	Executive Summary	
1	Marginal Distribution Customer Access Cost	Nathan Chau
2	Marginal Distribution Demand Cost	Louis Irwin
3	Marginal Generation (Commodity) Capacity Cost	Benjamin Gutierrez
4	Marginal Generation (Commodity) Cost	Synapse
5	Sales Forecast	Eric Duran
6	Revenue Allocation	Aaron Lu
7	Residential Rate Design	Cherie Chan
8	Small Commercial Rate Design	Nathan Chau

EXECUTIVE SUMMARY

In this report, the Office of Ratepayer Advocates ("ORA") presents its testimony for San Diego Gas and Electric Company's ("SDG&E") General Rate Case ("GRC"), Phase II, Application ("A.") 15-04-012. This proceeding is intended to update marginal costs, revenue allocation, and electric rate design.

ORA has made several recommendations designed to improve the way SDG&E calculates marginal costs. These improvements reduce the revenues allocated to residential and small commercial customers. ORA proposes that SDG&E's residential rates should be based on rates adopted in Resolution E-4787 and future Tier 1 rate increases should continue to be capped at the Residential Average Rate ("RAR") plus 5%. ORA recommends rejecting SDG&E's proposed increases to fixed charges and proposes transitional Time-of-Use ("TOU") rates and TOU configurations for small commercial customers.

Summary of Key ORA Recommendations

I. Marginal Costs

ORA made a number of significant recommendations and modifications to SDG&E's approach on how to calculate marginal costs.

A. Marginal Distribution Customer Access Cost

1. ORA recommends that the Commission adopt marginal customer access costs based on the "New Customer Only" ("NCO") methodology.
2. ORA recommends that new meter installations should be used to approximate the number of new connections.
3. ORA bases Operation and Maintenance ("O&M") escalators on routine O&M costs.

The combined impact of SDG&E's proposed marginal customer costs would greatly disadvantage SDG&E's smaller customers. For these reasons, ORA strongly recommends that the Commission not adopt SDG&E's proposed marginal customer access costs. ORA's recommended marginal customer access costs are listed below.

Customer Class	Marginal Customer Costs 2016$/Customer/Year	
	SDG&E	ORA
Residential Class Average	$152.61	$69.07
Small Commercial Class Average	$530.97	$258.25
Medium/Large Commercial & Industrial Class Average	$2,412.34	$1,874.94
Agricultural Class Average	$1,020.28	$383.47
Lighting Class Average (Cost Per Lamp)	$12.95	$4.16

B. Marginal Distribution Demand Costs

ORA finds that the regression method using combination of historical and projected data to calculate the marginal distribution demand costs is appropriate. However, ORA recommends modifications to SDG&E's data, including not using SDG&E's older historical data and using more up to date load forecast. ORA proposes marginal distribution demand costs are shown below.

Proposal	SDG&E ($/kW)	ORA ($/kW)	Difference
Feeders and Local Distribution	77.97	104.57	34.1 %
Substations	22.05	29.06	31.8 %

C. Marginal Generation Capacity ("MGCC") and Energy Costs ("MEC")

1. ORA recommends an annual capacity value, or MGCC, of $91.83 per kW-year, based on a modification to SDG&E's proposed Real Economic Carrying Charge ("RECC") methodology to reflect the lack of need for new generating capacity before 2019.
2. ORA recommends allocating marginal generation capacity costs to customer classes and TOU periods based on the relative loss of load probability ("LOLP") of all the hours.
3. ORA conducted production cost modeling and loss of load probability modeling to calculate hourly marginal energy costs ("MEC"), hourly LOLP, and total marginal generation costs (MGCC + MEC).

4. ORA also proposes changes to Time-of-Use ("TOU") periods, but recommends having only two periods—on-peak and off-peak periods. This should be easier for customers to understand than the three periods SDG&E proposes. ORA proposes an on-peak period of 4 pm to 9 pm during non-holiday weekdays and an off-peak period in all other hours. ORA hopes that making weekend hours off-peak will make the behavioral shift of responding to new TOU hours easier for residential customers.

5. The following table presents ORA's recommended marginal generation costs.

2016 Summer	Summer = July-October		
$/MWh, $2016	**MEC**	**MCC**	**MGC**
On-Peak	53.0	112.7	165.7
Off-Peak	44.0	11.7	55.6
Ratio On/Off Pk	1.2	9.6	3.0
2016 Winter			
$/MWh, $2016	**MEC**	**MCC**	**MGC**
On-Peak	50.7	10.2	61.0
Off-Peak	41.0	0.9	41.9
Ratio On/Off Pk	1.2	11.0	1.5

On-Peak Hours = Non-Holiday Weekdays, 4PM-9PM, Off Peak Hours all else. MCC allocation based on all-hours LOLE. RPS adder included.

II. Sales Forecast

The Commission should reject SDG&E's proposal to use advice letters to update its annual sales data and direct SDG&E to continue to update its sales forecasts via the Energy Resource Recovery Account ("ERRA") Forecast proceeding.

III. Revenue Allocation

ORA recommends the following:

1. ORA's marginal costs to allocate revenue responsibilities;
2. ORA's proposed TOU periods;
3. Equal cents per kWh allocator for the SGIP;

4. Equal cents per kWh allocator for CSI costs (with an exemption for CARE customers); and
5. ORA's caps and floors for class average rates in the proposed revenue allocation.

The following table shows the comparison between SDG&E's and ORA's proposed class average rates

		SDG&E[1]		ORA	
	Current Total Rate (¢/KWhr)	Proposed Total Rate (¢/KWhr)	Total Rate Change (%)	Proposed Total Rate (¢/KWhr)	Total Rate Change (%)
Residential	22.943	25.649	11.79%	24.272	5.79%
Small Commercial	23.798	25.693	7.96%	25.002	5.06%
Med&Lg C&I	19.977	19.116	-4.31%	20.428	2.26%
Agriculture	17.886	17.153	-4.10%	18.171	1.59%
Lighting	19.726	22.420	13.66%	20.631	4.59%
System Total	21.443	22.346	4.21%	22.345	4.21%

IV. Residential Rate Design

ORA recommends the following:

1. SDG&E's residential rates should be based on the rates adopted in Resolution E-4787 as a starting point, and as the basis for future Tier 1 rate increases.
2. The residential rates from Resolution E-4787 should be escalated by ORA's proposed revenue allocation to the residential class.
3. Future Tier 1 rate increases should continue to be capped at RAR[2] +5% % (relative to rates for the prior twelve months), which will continue to allow progress in narrowing the differential between Tier 1 and Tier 2 rates.

[1] SDG&E's proposed total rate is from the Consolidated Model GRC 2 (Amended in February 2016), "Class Avg Rates Adj – Year 3" tab, cells Q30 to Q40. ORA's proposed total rate includes a 1.5% cap on the system average rate.

[2] The Residential Average Rate

4. The rate changes from this GRC Phase 2 proceeding should be implemented at the same time as SDG&E's 2017 rate reform advice letter.

V. Small Commercial Rate Design

ORA recommends the following:

1. Reject SDG&E's proposed increases to fixed charges;
2. Adopt the following transitional TOU rates with flatter on-peak to off-peak rate differentials;

ORA's Proposed TOU-A-P Rates

TOU-A-P[3]			
Basic Service Fee	Current	SDG&E	ORA
0-5 kW	$7.00	$14.00	$7.00
5-20 kW	$12.00	$24.00	$12.00
20-50 kW	$20.00	$40.00	$20.00
>50 kW	$50.00	$100.00	$50.00
RYU Adder	$1.17	$1.87	$1.03
Energy Charge			
Summer On-Peak	$0.26359	$0.32506	$0.32118
Summer Off-Peak[4]	$0.23490	$0.25083	$0.27277
Summer Super Off-Peak[5]	$0.20443	$0.18958	$0.22659
Winter On-Peak	$0.23006	$0.22504	$0.24412
Winter Semi-Peak	$0.21588	$0.21440	
Winter Super Off-Peak	$0.19623	$0.20390	$0.22391

[3] TOU-A-P is the default TOU-CPP rate

[4] Currently designated as "Semi Peak"

[5] Currently designated as "Off-Peak." However, SDG&E's consolidated model uses the old designations.

ORA's Proposed TOU-A Rates

TOU-A[6]			
Basic Service Fee	Current	SDG&E	ORA
0-5 kW	$7.00	$14.00	$7.00
5-20 kW	$12.00	$24.00	$12.00
20-50 kW	$20.00	$40.00	$20.00
>50 kW	$50.00	$100.00	$50.00
Energy Charge			
Summer On-Peak	$0.30218	$0.41095	$0.33867
Summer Off-Peak	$0.26717	$0.25083	$0.29367
Summer Super Off-Peak	$0.22570	$0.21362	$0.24867
Winter On-Peak	$0.23006	$0.22504	$0.24412
Winter Semi-Peak	$0.21588	$0.21440	
Winter Super Off-Peak	$0.19623	$0.20390	$0.22391

3. Adopt the following TOU period definition for schedules TOU-A-P and TOU-A.

ORA's Proposed Small Commercial Class TOU Periods

TOU period	Summer	Winter
On-Peak	4 PM - 9 PM **Weekdays**	4 PM - 9 PM **Weekdays**
Off-Peak	6 AM - 4 PM, and 9 PM to Midnight, Summer **Weekdays**	N/A
Super Off-Peak	All other periods (*including weekends*)	All other periods (*including weekends*)
Seasonal Description	July through October	November through May

4. Retain many of the rate elements that currently exist on SDG&E's schedule A-TOU, and recommend that SDG&E rename this schedule.

[6] TOU-A is a traditional TOU rate without a CPP element. This is the rate the majority of customers opting out of TOU-A-P would likely opt in to.

CHAPTER 1

MARGINAL CUSTOMER COSTS

NATHAN CHAU

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CHAPTER I
MARGINAL CUSTOMER COSTS
NATHAN CHAU

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

This chapter presents ORA's recommendations on SDG&E's marginal customer costs that should be used in SDG&E's GRC Phase 2 proceeding, A.15-04-12. In summary ORA's recommendations are:

1) The Commission should use the New Customer Only ("NCO") method to calculate marginal customer costs.
2) New meter installations should be used to approximate the number of new connections.
3) O&M escalators should be based on routine O&M costs.

These adjustments result in the following annual marginal customer costs segmented by class:

Customer Class	Marginal Customer Costs 2016$/Customer/Year	
	SDG&E	ORA
Residential Class Average	$152.61	$69.07
Small Commercial Class Average	$530.97	$258.25
Medium/Large Commercial & Industrial Class Average	$2,412.34	$1,874.94
Agricultural Class Average	$1,020.28	$383.47
Lighting Class Average (Cost Per Lamp)	$12.95	$4.16

[1]

Marginal Customer Access Costs ("MCACs")[2] are the incremental customer costs that vary with the number of customers in each customer class and are the costs that change when the utility **adds a customer**. Unlike the marginal

[1] The "Amount overstated" by rental method calculations only takes in to account the differences in the TSM cost component between the rental method and the NCO methods employed by SDG&E and ORA respectively.

[2] Marginal customer costs ("MCC") and MCAC will be used interchangeably.

cost of procuring energy, these costs do not vary with changes in usage or peak demand. Marginal customer costs make up a significant portion of total distribution marginal costs and are a significant input into the revenue allocation process that results in rate changes. Marginal customer costs include the capital costs of the final line transformer, service and meter ("TSM" or "hookups")[3], equipment that provide new customers access to the electrical grid, operations and maintenance ("O&M") costs associated with this equipment and any ongoing customer service-related costs. The customer services costs in turn include the costs of metering, collections, billing, and customer inquiry services.

While SDG&E's supports using the rental method in quantifying the capital-related costs, ORA supports the New Customer Only ("NCO") method to calculate marginal customer costs. The NCO method appropriately aligns with marginal cost pricing and should be the basis for calculating capital-related costs because it captures ***new*** (i.e. costs of adding a customer) as opposed to ***historic sunk*** costs of hook-ups. In its implementation of this methodology, ORA excludes non–customer growth-related events and costs (i.e. replacement costs) from marginal cost calculations in order to better reflect the manner in which the relevant costs are incurred when customers connect to the grid. Though SDG&E favors the rental method, it also provided ORA with a pro forma calculation of marginal customer costs using the NCO method.

II. SDG&E'S PROPOSED METHOD

SDG&E's proposed method uses total weighted costs of transformers, service lines and meters for each rate schedule which are adjusted for various loading factors, and then converted to an annualized rate using a real economic carrying charge ("RECC" or "Rental Method"). SDG&E uses this RECC factor in order to reflect the annual capital rental obligations of each customer.[4]

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[3] Also referred to as the "TSM method" of identifying hook up facilities.

[4] This methodology is known as the "rental method."

In developing its O&M component of marginal customer costs, SDG&E analyzed the "2013 Federal Regulatory Commission ("FERC") Form 1 distribution O&M account costs (Accounts 580-598) in order to separate the costs related to customer connections. The total O&M costs for that year were adjusted by an administrative and general ("A&G") factor. The resulting amount of O&M costs were then allocated based on a "factor derived from each schedule's relative (percentage) responsibility of the grand total of TSM costs"[5] before being converted to a per-customer rate.

In accordance with the 2012 Test Year GRC Phase 2 Partial Settlement Agreement adopted by D.14-01-002[6], SDG&E conducted "an internal study of historical customer service costs to determine the appropriate allocation of each type of cost for marginal distribution cost purposes." The final annual MCAC responsibility per customer is the sum of the annualized TSM, O&M and customer service costs.[7]

III. DISCUSSION & ORA'S PROPOSALS

A. Policy Background

Long-standing commission policy considers marginal cost-pricing to be a superior alternative to embedded cost pricing in providing accurate price signals to customers, as it based on the change in costs of providing or withdrawing an incremental unit of service.[8] This pricing methodology aligns the customers' decisions to use energy services with the utility's cost of making small changes in the amount of those services that are provided to customers. It therefore

[5] A-15-04-012 SDGE 2015 GRC2, Chapter 4 Testimony, William G. Saxe, page 9

[6] Section 3.A-Marginal Costs, p. 4

[7] A-15-04-012 SDGE 2015 GRC2, Chapter 4 Testimony, William G. Saxe, pages 6-9

[8] Decision 92549, Section B1: Staff Position on Marginal Cost Pricing; D.92-12-058, pages 7 and 20; D.92-12-057, page 4; D.15-07-001, Page 28, Rate design principle: Rates should be based on marginal cost.

necessarily excludes the historical costs that remain on the utility's books that essentially are sunk and unchangeable.

With the intention of closely aligning rate-making practices with marginal costs in the context of customer costs, only the incremental costs of adding new customers should be used for computing marginal hookup costs. SDG&E's proposed rental method captures the cost of ***all*** existing hookup equipment, and thus it reflects more of an embedded cost approach rather than a marginal one. Only the costs incurred by the utility for dispatching equipment to connect new customers in a given year are truly marginal.

Beginning with its decision in PG&E's Test Year 1993 GRC[9], the Commission has consistently rejected the Rental Method because it found that the Rental Method overcharges customers for the cost of their TSM equipment.[10] Thus, the revenue allocation resulting from the RECC methodology applied to TSM overstates the role of the customer connection in cost causation and erroneously skews costs to small customers. The Commission has judged that NCO best reflects cost causation for TSM facilities[11] and customers accessing the electric network. In support of the NCO method over the rental method, the Commission made the following Findings of Fact in 1996:[12]

> 37. The rental method does not produce a competitive price for customer hookups and, in fact, ***significantly overstates the price that would prevail in a competitive market.***
>
> 38. Under the rental method, and the associated RECC assumptions, Edison's marginal customer costs exceed the cost of hooking up new customers, installing replacements and covering the variable expenses for all customers.

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[9] D.92-12-057, 27.7

[10] Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal.PUC LEXIS 270, D.96-04-050. FOF 37 and 38. These findings are consistent with Commission findings in Decisions 92-12-057, 95-12-053, 97-03-017, and 97-04-082 spanning both gas and electric utilities and including PG&E, SCE, SDG&E, and SoCalGas.

[11] Application of PG&E (1992) 47 CPUC 2d 143, 1992 Cal. PUC LEXIS 971, D.92-12-057.

[12] See Footnote 12

In order to align marginal costs of hook-ups with true cost causation, the Commission should retain the logic of its prior Decisions and continue to use the NCO method for calculating MCACs.

B. The Case Against the Rental Method

The rental method collects annual charges over its life that equals the revenue requirement of installing TSM equipment. One justification for using the rental method in hookup cost calculations is to reflect that a ***"competitive"*** rental market exists for TSM equipment in which customers pay the same real annual charge, or "rent" in terms of purchasing power. This annual charge represents the full cost of using a machine for one year rather than next. This charge is escalated by an inflationary factor to preserve the purchasing power of that annual charge year over year in order to account for higher replacement costs in a world in which prices are increasing. It begins at a levelized stream (like a mortgage) at the beginning of an asset's life and escalates at an inflation rate "*i*" each year. By the time the machine is replaced at a much higher cost, the annual charges on the new machine continue in an uninterrupted series. ***Effectively, the carrying charge to an old plant in any year equals the first year carrying charge on a new plant in the same year***. Each subsequent annual charge represents the full annual cost of using a machine as if a new one were purchased that year. Thus, the Rental Method treats equipment as one that produces at a constant rate and simply expires at the end of its life. However, equipment loses efficiency and begins to degrade with age and usage, requiring more maintenance.

SDG&E asserts that the rental method sends a more accurate and more reasonable price signal on the cost of providing an individual customer access to the electrical system.[13] In reality, the assumptions built in to the Rental Method are nonsensical for hook ups since costs are covered entirely up-front pursuant to

[13] SDG&E A.15-04-12, Chapter 6, Prepared Direct Testimony of William J. Saxe, WGS-7, December Filing.

Rules 15 and 16.[14] The rental method is used to represent the continued services derived from such facilities. However, it is not in alignment with marginal cost-based rate setting principles to continually charge customers based on value derived as opposed to costs incurred. The NCO method is a much better proxy for marginal costs because it appropriately focuses on the marginal costs of the asset, not its value. Pricing derived from customer value of service is not reflective of a firm that is a price taker, and is therefore not competitive.

The Rental Method treats all existing equipment the same regardless of vintage by ignoring capital depreciation and sunk costs. In other words, the rental method allocates the cost of TSM equipment to customers as if the costs are fully recoverable at any point in the asset's useful life. In reality, the costs associated with adding a customer usually requires installation of a TSM hookup. Once installed, most of the costs deployed to hooking up that customer are sunk and the cost cannot be recovered even if the utility is no longer obligated to serve that customer and/or is permanently dismantled.[15] Labor costs that were associated with the installation of this equipment cannot be recovered, and TSM equipment, particularly service drops, has very little to no salvage value.

1. The Rental Method is Indifferent to Vintage of Equipment and Ignores Depreciation

There are very few competitive markets where the Rental Method's assumed "age-indifference" logic applies. Utility equipment must eventually be replaced, as natural wear and tear overtime will lead to its complete retirement despite routine maintenance.

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[14] Rule 15 section C, referenced in Rule 16 section E. "The utility will complete a Distribution Line Extension without charge provided utility's total estimated installed cost does not exceed the allowances from permanent, bona-fide loads to be served by the Distribution Line Extension within a reasonable time, as determined by utility."

[15] However, the utility remains obligated in maintaining the infrastructure that was put into place even when a premise is vacated. See Section C4 "Replacement Rates."

In competitive markets, rents on equipment should decline with age and use in order to reflect higher maintenance costs, declining operative efficiency associated with aging, and customers' preference for newer equipment. When given a choice to pay the same rent on new equipment versus an older one, customers will opt for the newer one. The absence of an active secondary market for electric customer hookup equipment further reinforces the impossibility of resale at full current market value. In cases where a utility does manage to sell old equipment, it is never priced at replacement cost new ("RCN"), nor would anyone want to purchase older equipment at this price.[16] Instead, sale of older distribution equipment is generally priced at or less than replacement cost new less depreciation ("RCNLD"). Similarly, automobiles are required by law[17] to have a functioning odometer in order to effectively measure use. Generally, cars with more mileage are worth less than new cars.

C. Application of the New Customer Only Calculation

The NCO approach considers only the full upfront cost of new connections as marginal. These fully-loaded TSM costs are socialized (shared) by all customers within a class. In using the NCO method, a utility's "new customers" must be defined and quantified. One challenge with this is the issue of how to address the incongruence between the avoided costs when a utility loses a customer and those costs incurred from to serve a new customer on the margin.[18]

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[16] PG&E response to ORA-PG&E Data Request 3, Question 7, A.11-03-014. "Since the inception of the SmartMeter™ Project, PG&E has disposed of its analog meters by selling them to recycling companies for the value of the metal. PG&E did not attempt to sell these meters based on the results of an analysis conducted when the Project began. In this informal analysis, PG&E contacted potential interested purchasers of the removed analog meters to determine a possible selling price; the resulting estimated price was approximately $1 per meter… In 2009, the last time PG&E performed a study to determine the proceeds from the recycling process, the average gross salvage from retired meters was $0.24 per meter."

[17] 49 USC Ch. 327: Odometers

[18] See explanation in section B. When a utility discontinues a connection permanently (even though this probably rarely happens), the equipment is sold a lower price than the real cost it took to build it/cost of replacing that facility. Moreover, the labor costs associated with establishing those connections cannot be recovered. Therefore, the utility really only avoids,

(continued on next page)

Under the NCO method, the TSM cost obligations per customer is typically computed by multiplying the growth rate of a customer class[19] by the total cost of hooking up one new customer (to get the cost of hooking up all new customers), and dividing that by the total number of customers in the class. Sometimes the replacement rate of existing equipment is included in the calculation as if it were a new customer.

1. Intra-Class Tariff Migrations Distort Customer Growth Rates

The traditionally-used customer net growth rate parameter obscures the number of new connections since these growth rates fail to capture the number of new customers in isolation of those terminating service or switching schedules. Therefore, when there are more customers leaving service than those coming in, or when net growth rates would be negative, the analysis yields negative marginal costs calculations. Often a floor of zero is imposed on the net growth rate to avoid calculating nonsensical negative marginal costs. Even in years of contraction, there is always the possibility that new connections are being established.

There are conspicuous drawbacks in using "new customers" as a proxy for the number of "new connections." Each "customer" tracked by SDG&E represents an actively-metered connection.[20] *Anyone new to SDG&E's service area is considered a new customer, even if that customer has taken up residence in a home that is already connected to the grid.*[21] **SDG&E would incur no additional hook up costs from simply reactivating an existing meter to serve them**.

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operations and maintenance costs on that connection.

[19] This can be number of new customers in the class, or the growth rate. Marginal hook up cost per customer = (number of customers + replacements)*fully loaded cost of capital/number of customers in class.

[20] SDG&E response to Data Request 007, Question 1A, April filing. "The number of customers identified does not equate to the number of billed accounts but instead represents the number of active customer meters."

[21] For example, any customer who moves from PG&E's service area to SDG&E's service area would be counted as a new customer.

Additionally, the reality of tariff migrations[22] within classes exposes further weakness in applying this methodology. Those who are opting into a new tariff from another can create the illusion that a new connection is being established. A customer who simply switches rates does not impose the need to establish new connections.[23]

These discrepancies between the number of connections being established and the growth rate metric are illustrated in the table below.

Table 1-1

	Residential			**Non-Residential**		
	(A)	**(B)**	**(B-A)/A**	**(C)**	**(D)**	**(D-C)/C**
	New Meter Installations	Change in Number of Customers	Discrepancy	New Meter Installations	Change in Number of Customers[24]	Discrepancy
2008	7,930			4,358		
2009	7,152	7,620	7%	2,711	-354	-113.05%
2010	4,724	7,602	61%	2,257	-3	-100.14%
2011	5,516	6,916	25%	2,226	864	-61.18%
2012	5,889	6,419	9%	2,366	554	-76.57%
2013	6,333	7,075	12%	2,530	465	-81.60%
2014	7,447	6,864	-8%	2,473	858	-65.33%

ORA asked SDG&E whether these discrepancies can be explained by some possible lagged effects between the planning/building of new connections and the

[22] This number may be as large a number as the numbers of customers terminating service.

[23] The customer is still residing in the same home. Therefore, no new hook ups are needed. Take for example that 100 customers are opting in to EV-TOU2, a time-differentiated rate for electric vehicle customers, from schedule DR. EV-TOU2 would register an increase of 100 customers with an equivalent decrease for schedule DR. But to avoid non-sensible negative marginal costs, DR's negative growth is floored at 0. However, what would happen is that the class as a whole would show a 100 artificial increase in the number of customers, which does not make sense since there are no new connections associated with that intra-class migration.

[24] SDG&E response to ORA-SDG&E DR 007, question 3. In "ORA DR-007, Question 3" work papers, take sum of non-residential customers in one year and subtract sum of non-residential customers in the previous year.

time at which those connections are active. SDG&E affirmed that these differences in a given year can be partially explained by the lag effect.

> SDG&E adds "*that the new meter installations reflect the number of new meters installed at new facilities while the change in the number of customers reflect the change in the number of customers taking electric service with SDG&E* ***at both new facilities and existing facilities****. For this reason, a new customer taking electric service at an existing facility that already has a meter would reflect a change in the number of customers* ***but would not*** *reflect a change in new meter installations; thus, contributing to the differences shown for new meter installations versus the change in the number of customers.*"[25]

Based on this information, utilizing the "number of new meter installations" is a superior alternative to customer growth with greater alignment with marginal costs.

2. "New Meter Installations" Better Captures the Growth Rate of New Connections

ORA uses the number of new meter installations to reflect the ***actual*** number of new connections in a given year. In a data request response, SDG&E provided the number of new meters installed in years 2008-2015.

> "New meter installations reflect the installation of a meter at a location **where no meter previously existed**. A **customer moving** from one tariff to another **would not be reflected** in the number of new meter installations."[26]

ORA extrapolates the number of new meter installations for 2016, 2017 and 2018 based on historic trend of installations from 2011 to 2016. This trend analysis excludes years of economic contraction in order to better approximate more

[25] Data Request 007, new filing (February or April?), Question2(C).

[26] Years 2008- 2014 SDG&E's response to ORA-SDG&E-Data Request-001, Question 2, part A, and 2015 figures provided in Data Request 07, of the amended filing.

current and relevant economic realities associated with service expansion.[27] The rate at which new connections are being built has been increasing and is likely to continue to increase, at least in the short run, if current economic conditions persist.

A three-year average is calculated from these forecasted values generated from a straight line linear regression methodology.[28] These values are illustrated in the table below.

Table 1-2

Class	Actual New Meter Instllations					Extrapolated			
	2011	2012	2013	2014	2015	2016	2017	2018	Average 2016-2019
Residential Customers	5,516	5,889	6,333	7,447	8,734	9,182	9,981	10,781	9,981
Non-Residential Customers	2,226	2,366	2,530	2,473	2,608	2,702	2,789	2,876	2,789

This average is then reallocated to each schedule/subgroup depending on its share of the total number of new customers for years 2016-2019 forecasted by SDG&E to approximate the number of new connections for each schedule.[29]

The distribution concerning customers in schedules DR-SES and EVTOU will be discussed later in this testimony.

[27] The average of the most recent years is used in order to better approximate the number of new connections going forward. (need to explain more here)

[28] SDG&E's NCO calculation uses a three-year average of forecasted number of new connections for years 2016, 2017 and 2018. For consistency, ORA employs a similar methodology of using three forecasted years of new meter installations.

[29] For example, if 232 of the 833 2016-2019 average number for forecasted non-residential customers are small commercial customers with maximum annual demands less than 5kW, then 232/833, or 27.85% of the 2789 new meter installations would be allocated to that subgroup. NCO for Question 2 of ORA Data Request 001 work papers. This allocative method will not be applied to all schedules since some schedules, such as EV-TOU2 and DR-SES which are opt-in schedules. Customers who merely opt in from one schedule to another do not impose the need to build new connections. They are only charged differently for service.

3. Replacement Costs are not Growth-Related

Replacement costs for TSM are not incurred as a result of adding customers or can be avoided unless the property is abandoned, which rarely happens. In fact, in its last GRC in 2014, the Pacific Gas and Electric Company (PG&E) excluded replacement costs altogether on the basis that they are not growth-related, a practice that ORA agrees with in principle.[30] However, once a new connection is established, it imposes the obligation to maintain that equipment going forward. Thus ORA includes only the subsequent replacements associated with new connections made in a given year. For existing connections, customer turnover and temporary vacancies do not impose any additional obligations to maintain the access equipment at the margin because this obligation was placed on the utility at the time of installation.[31] Moreover, SDG&E did not include replacement costs in calculating marginal distribution demand costs "because these costs are not growth related."[32]

Only the additional obligation to replace newly installed equipment should be included in marginal cost calculations while ongoing replacement costs associated with existing equipment are implicitly accounted for in the equal percent of marginal cost scalars. ORA has opted to adjust the capital hook up costs by including a lifetime replacement cost multiplier on new connections only, to reflect the marginal obligation to periodically replace hook up equipment upon asset retirement.[33] This cost adder captures the present value of the stream of future costs associated with replacing equipment that is part of the NCO calculation indefinitely.

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[30] Pacific Gas and Electric Company 2014 GRC 2 Prepared Testimony, Exhibit (PG&E-2) Volume 1 Marginal Costs, 7-5

[31] 7-11 PGE testimony 7-11 footnote 18

[32] Lines 12-15 of SDG&E William G Saxe Testimony, Marginal Distribution Demand Costs

[33] This lifetime replacement cost adder reflects the present value of an infinite cash flow necessary to replace equipment indefinitely given an assumed inflation rate, discount rate, and asset life.

D. Operation and Maintenance Cost Definitions

Operations and Maintenance ("O&M") costs are those ongoing costs associated with maintaining TSM equipment in order to ensure their functional reliability. SDG&E used FERC accounts 580-598 to arrive at total distribution O&M costs. ORA conducted further investigation into the accounts and takes no issues with using them to quantify O&M costs as they all vary with the number of connections according to the expense coverage and type for each account. The resulting amount of O&M costs were then allocated based on a "factor derived from each schedule's relative (percentage) responsibility of the grand total of TSM costs" before being converted to an average $/year rate for each customer. ORA does not dispute this allocation methodology.

SDG&E then scales up the O&M costs by multiplying them by an Administrative and General ("A&G") factor. ORA takes issue with the manner in which this A&G factor is escalated.

1. Exclusion of Extraordinary Events as Marginal

SDG&E proposes to employ an A&G factor that is double what was applied to O&M costs in the previous GRC proceeding in 2012, overstating marginal cost responsibilities. SDG&E mainly attributed this increase to significant unforeseen fire damage that precipitated a spike in its fire insurance premiums. ORA does not agree in including them in marginal costs because these costs were the result of extraordinary events that do not relate the cost of having to serve additional customers. These expenses should be collected in the revenue requirement scalars and not via marginal customer costs. Having excluded these costs, the A&G factor decreases from 38.51% to 18.91%[34] , resulting in a reduction of about 9% in O&M costs per customer.

[34] SDG&E GRC 2 2012

Operations and Maintenance Costs 2016$/Customer-Year

	SDG&E	ORA
Residential Class Average	$32.76	$29.65
Small Commercial Class Average	$123.79	$112.01
Medium/Large Commercial & Industrial Class Average	$537.40	$486.28
Agricultural Class Average	$220.37	$199.41
Lighting Class Average (Cost Per Lamp)	$3.40	$2.92

IV. CONCLUSION

The NCO method is a superior methodology reflecting the true marginal costs of serving new customers, whereas inclusion of the cost of all existing hookups via the Rental method inflates the marginal customer costs. “New meter installations” captures the true number of new connections installed better than “new customers,” since it is not distorted by intra-class tariff migration. In regards to the various opt-in schedules available to SDG&E’s Residential class, caution needs to be exercised to include only the costs of new hookups they need. The Commission should adopt ORA’s proposals as they better represent how costs are actually incurred.

CHAPTER 2

MARGINAL DISTRIBUTION DEMAND COSTS

LOUIS IRWIN

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CHAPTER 2
MARGINAL DISTRIBUTION DEMAND COSTS
LOUIS IRWIN

I. INTRODUCTION AND RECOMMENDATIONS

This chapter addresses San Diego Gas & Electric's ("SDG&E's") marginal distribution demand costs ("MDDC"). The MDDC values are necessary to allocate revenue responsibilities to the various rate classes. MDDC includes substation, feeders, and local distribution costs. The feeders and local distribution system are facilities needed to transmit electricity between the substations and the final line transformers. The marginal distribution demand costs are the investments needed to serve an incremental load. Thus, investments serving repairs, safety, and reliability not attributed to increasing load are excluded.

SDG&E calculates the MDDC by performing a linear regression between load-growth related investments in dollars and annual incremental peak loads in kilowatts ("kWs").[1] The resulting MDDCs are expressed as dollars per kW.

SDG&E gives undue weight to the historical trend by choosing to include twelve years of recorded data but only three years of forecast data for the regression analysis. Furthermore, due to the lengthy GRC process, part of SDG&E's short "forecast" of 2014 to 2016 became "historical," at least on the basis of the calendar, leaving very little of the "forecast" looking beyond the present. SDG&E's load forecast is unjustifiably high when compared to California Energy Commission's ("CECs") latest forecast.

ORA recommends the following three modifications to SDG&E's MDDC forecast:

1. The regression method should be more consistent with standard methods. The historic period should not cover years 2002 and 2003 data as proposed by SDG&E).

[1] Two data series essential to this analysis are the investment costs and the added capacity. The regression finds the trend line which minimizes the square of the distance between the trend and the data sets.

2. SDG&E's load forecast should be adjusted by using SDG&E's weather normalized ("W/N") actuals for 2014 instead of SDG&E's load forecast that relies in part on 2013 CEC data.[2]

3. The forecast values SDG&E proposes for 2015 and 2016 should be replaced with the CEC's 2015 Revised forecast for those years.[3]

The results of ORA's recommendations are shown below in Table 2-1.

Table 2-1 Comparison of SDG&E and ORA MDDCs ($ / kW)

Proposal	SDG&E	ORA.	Difference
Feeders and Local Distribution	77.97	104.57	34.1 %
Substations	22.05	29.06	31.8 %

II. SDG&E'S FORECAST METHOD IS INCONSISTENT WITH NERA RECOMMENDED GUIDELINES

SDG&E bases its forecast of the MDDC on an approach first developed by the National Economic Research Associates ("NERA") Consulting Group. NERA recommends using ten years historical and five forecast years. This approach also has been adopted by the Commission in various revenue allocation and rate design proceedings.[4] SDG&E deviates from the NERA model by (1) reducing the forecast period to three years and lengthening the historical data to twelve years, and (2) applying the weather normalization process to the annual peak loads.

SDG&E only uses three years of forecasting data compared to the NERA recommendation of using five years of forecast data. When asked about this deviation, SDG&E responded that for investments, a three year forecast is what its

[2] In DR-005, response 1a, SDG&E cites California Energy Commission report "CEC-200-2013-004-V1-CMF" and V2, December 2013.

[3] California Energy Demand 2015 Revised, Form 1.4, California Energy Commission, December 2015.

[4] For instance, SCE GRC 2015, A.14-06-014, Exhibit 2.

Planning Department was able to provide.[5] This effectively caps the forecast at three years (ending in 2016). Although ORA generally supports the NERA model, forecasts do tend to lose power the further out they go and therefore the loss of the final two years of forecast data by itself is a modest shortfall. In addition, the current forecast environment has extra challenges due to changes in distributed generation, climate change issues, and new energy efficiency measures.[6] These changing elements are making the forecast more controversial. Therefore, giving less weight to the forecast period is a more supportable and safer choice.

In deviating from the standard practice recommended by NERA, SDG&E adds two years of older data (2002 and 2003), without providing justification for this choice.

NERA model limits the historical trend data to ten years. This is well justified as the further back one goes, the less likely the conditions will remain similar. SDG&E includes two added years, 2002 and 2003, which were right in the midst of the California energy crisis recovery period. Adding these two years does in fact influence the load trend substantially by providing a significant rebound and bumps the entire trend upward. ORA calculates the average annual increase in weather-normalized loads for the NERA recommended ten-year period to be 1.10%. By using SDG&E's method of including two additional historical years, the growth figure increases to 1.78%. Proportionally, this higher growth rate is over 50% more aggressive than the ten-year trend. The data can be seen in Table 2-2 below.

[5] Per phone conference with SDG&E, March 8, 2016. ORA did not have a credible method or source to extend SDG&E's investment forecast beyond the three years that SDG&E provided.

[6] 2015 Integrated Energy Policy Report, California Energy Commission, February 24, 2016, p. 130 – 142.

Table 2-2 SDG&E Historical Annual W/N System Peak Loads (MW)

Year	SDG&E	ORA	Percentage Growth
2002	3,636		
2003	3,764		3.51%
2004	3,998	3,998	6.21%
2005	4,101	4,101	2.58%
2006	4,178	4,178	1.87%
2007	4,366	4,366	4.52%
2008	4,337	4,337	-0.68%
2009	4,232	4,232	-2.42%
2010	4,084	4,084	-3.49%
2011	4,251	4,251	4.08%
2012	4,320	4,320	1.62%
2013	4,413	4,413	2.16%
Average %	1.78%	1.10%	

III. SDG&E'S LOAD FORECAST SHOULD BE ADJUSTED BY USING SDG&E'S WEATHER NORMALIZED ("W/N") ACTUALS FOR 2014.

SDG&E's refiled application should have included actual historical data for 2014, instead of the forecast values that were used in SDG&E's initial filing. When Phase 1 of SDG&Es GRC was filed in November, 2014 data was not available in 2014, making 2014 a "forecast" year. This classification as "forecast" was because the historical data was not yet available. However, by summer 2015, well before the December 1, 2015 refiling, SDG&E had the actual loads and weather normalization data to create weather normalized loads for 2014.[7] In an ORA data request asking why SDG&E had not adjusted its forecast despite the

[7] From file GRCP2-System-Transmission-DistributionLoads (3-8-2016)xlsx, note 4 under right most table states that the 2014 W/N data was available in summer 2015. The table was included in a March 8, 2016 conference call.

weather normalized actuals being lower than SDG&E expected, SDG&E replied, "SDG&E felt at that time that a one-year down turn wasn't sufficient evidence to alter the forecast."[8] Instead, SDG&E made no adjustments, choosing to stick with the 2014 CEC forecast for 2014, only applying the other corrections for transmission level exclusion and AAEE adjustments.[9] The value used was 4,615 MW, while the weather normalized actual loads result in a value of 4,365 MW (a substantial 5.4% difference).[10] SDG&E made no changes to the 2015 and 2016 forecasts based on the implications that the lower than expected 2014 actual weather normalized loads might have had on the subsequent forecast for 2015 and 2016. The CEC, however, as will be described below, did revise its 2015 and 2016 loads downwards in subsequent forecasts.

SDG&E set aside actual 2014 data in favor of a forecasted projection that was over 5% different. The magnitude of this difference provides sufficient cause for ORA recommend bypassing the 2014 forecast in favor of the weather normalized actual loads.

IV. THE FORECAST VALUES SDG&E PROPOSES FOR 2015 AND 2016 SHOULD BE REPLACED WITH THE CEC'S 2015 REVISED AND UPDATED FORECAST FOR THOSE YEARS

SDG&E's demand forecast utilizes an outdated CEC forecast for years 2015 and 2016. The CEC's most recent Energy Demand Forecast (2015 Revised) includes updates that improve its accuracy, and should be used in developing SDG&E's forecast instead of the older numbers.

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[8] DR-009, Q. 4, February 1, 2016.

[9] A complete translation from CEC to SDG&E forecasts involves three adjustments. The body of the testimony has only addressed one – weather normalization. The other two conversions have been deemed less germane to this testimony. The adjustment for transmission is matter of scope or jurisdiction – the CEC SDG&E Planning Area includes transmission that is not actually within SDG&E territory. The new measure from the CEC, Additional Achievable Energy Efficiency ("AAEE") is tracked separately. Positive AAEE would decrease the load forecast, creating a lower net load forecast.

[10] GRCP2-System-Transmission-Distribution Loads (3-8-2016)xlsx cell C21.

Table 2-3 Evolution of CEC Forecasts

Year	2014 Forecast	2015 Initial Forecast	2015 Revised Forecast
2014	4,615	4,533	4,792
2015	4,654	4,625	4,453
2016	4,649	4,626	4,414

The 2015 Revised Energy Demand Forecast details how it has undertaken a wide variety of substantial improvements to address changing conditions and policy needs. One of the more influential changes is a tiered rate analysis to better project residential solar installation. The focus on PV includes projections by high, mid and low PV growth.[11] Additionally, the recently created measure of Additional Achievable Energy Efficiency ("AAEE") was substantially revised due to new energy efficiency standards, re-evaluations of past standards and uncertainty factors.[12] The result was a scale back from the original AAEE estimates by about 50%.[13] The 2015 Revised Forecast also includes shifting the measure from coincident to non-coincident peak.[14] To address the challenges of weather normalization, a climate model from the Scripps Institute of Oceanography was adapted to the California market.[15] Near-term changes will also include more localized analysis and hourly, rather than annual forecasts of

[11] California Energy Demand 2016 - 2026 Revised Electricity Demand Forecast, Volume 2: Electricity Demand by Utility Planning Area, California Energy Commission, January 15, 2016, Table 3-3, p. 66.

[12] 2015 Integrated Energy Policy Report, California Energy Commission, February 24, 2016, p. 132 and 138 – 140. Investigation of AAEE done by Navigant Consulting.

[13] For instance, comparing the 2016 AAEE estimates for the SDG&E Planning Area for the 2014 EDF versus the 2015 Revised (Mid Demand scenario, including losses: 120.36 MW (2014), 55.43 MW (2015 Revised). The new value is less than half the old value.

[14] 2015 Integrated Energy Policy Report, California Energy Commission, February 24, 2016, p. 132.

[15] 2015 Integrated Energy Policy Report, California Energy Commission, February 24, 2016, p. 137.

loads.[16] A close review of all these changes would reveal that some will deflate and others inflate the forecast. But overall, as shown above in Table 2-3, the effect is to dampen the forecast. ORA believes this latest CEC forecast has increased credibility.

The SDG&E and ORA proposed loads 2013 to 2016 are shown in Table 2-4 below. For contrast, the 2015 Revised CEC Energy Demand Forecast is included as well. The CEC forecast is adjusted for transmission and AAEE differences. The resulting annual peak load growth rate for ORA's proposal is nearly flat at 0.02%. This falls squarely between the SDG&E forecast result of 1.77% average annual growth and the 0.88% average annual decrease for the CEC Revised 2015 Energy Demand Forecast.[17] The CEC forecast comes in negative due to an unusually high value for 2014 and subsequent decline

Table 2-4 ORA vs. SDG&E and CEC Proposed Loads

Year	2015 Revised CEC	Percentage Growth	ORA	Percentage Growth	SDG&E	Percentage Growth
2013	4,550		4,413		4,413	
2014	4,792	5.32%	4,365	-1.09%	4,615	4.58%
2015	4,453	-7.08%	4,453	2.01%	4,654	0.84%
2016	4,414	-0.88%	4,414	-0.88%	4,649	-0.10%
Average		-0.88%		0.02%		1.77%

V. CONCLUSION

ORA recommends SDG&E's load forecast be modified in the three ways described above. These changes rely on more accurate and updated values, which

[16] 2015 Integrated Energy Policy Report, California Energy Commission, February 24, 2016, p. 132.

results in a forecast that has greater reliability and accuracy for the purposes of calculating MDCC.

CHAPTER 3

MARGINAL GENERATION CAPACITY COSTS

BENJAMIN GUTIERREZ

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CHAPTER 3
MARGINAL GENERATION CAPACITY COSTS
BENJAMIN GUTIERREZ

I. INTRODUCTION & SUMMARY OF RECOMMENDATIONS

The Office of Ratepayer Advocates ("ORA") has conducted a thorough review of San Diego Gas & Electric Company's ("SDG&E") marginal generation capacity costs ("MGCC") and finds SDG&E's proposed costs to be overstated by $26.33/kW-yr. ORA recommends a lower value of MGCC based on the deferral value of a gas-fired combustion turbine ("CT") plant from 2018 to 2019 and the choice of an advanced CT plant compared to the traditional CT technology SDG&E proposes. SDG&E separates its marginal commodity costs into marginal energy costs ("MEC") and marginal generation capacity costs, as has been the practice at the Commission for most of its over thirty-five years of marginal cost-based ratemaking. ORA's recommendation for MEC, based on analysis performed by Synapse Energy Economics ("Synapse"), is presented in Chapter 4 of its testimony, and in this chapter ORA presents its proposed value and discussion of MGCC. ORA recommends a value of $91.83/kilowatt-year ("kW-yr.") for MGCC, which is 22% less than SDG&E's proposed value. While ORA agrees with SDG&E's basic framework of estimating MGCC through the annualized cost of a gas-fired CT peaker plant less energy and ancillary services rents, ORA takes issue with several aspects of SDG&E's method and proposes the following modifications:

A. The CT plant's installation costs should be based on an advanced CT[1] peaker plant rather than a conventional CT.
B. SDG&E's MGCC should be based on the deferral value of a CT installed in 2018 and deferred to 2019—the earliest possible year that marginal capacity may be needed in SDG&E's service territory.

[1] The differences between an advanced CT and a traditional CT are discussed in Section II.A, below.

C. A 15% Resource Adequacy (RA) adder should be included in MGCC.

D. San Diego-Imperial Valley's weighted average RA capacity market price of $48.96/kW-yr. supports a MGCC value in the range proposed by ORA.[2]

E. ORA recommends using an All top Loss of Load Probability ("LOLP") hours method for MGCC revenue allocation using the results of Synapse's LOLP modeling. This is discussed further in Section IV of this testimony.

II. Policy Background

Marginal generation capacity costs ("MGCC") are traditionally defined as the increase in the total cost of generation capacity given an incremental increase in electricity demand.[3] These costs are typically driven by increases in peak demand, which put pressure on system capacity and cause the need for incremental, i.e. marginal, generation capacity.[4] SDG&E follows the practice held at the Commission for most of its over thirty-five years of marginal cost ratemaking of separating marginal commodity costs into marginal energy costs ("MEC")—or the costs of an additional unit of electricity given an incremental unit of electricity consumption—and MGCC, which it estimates through "the cost of building a new CT including all permitting, financing, and development costs, and deducting expected earnings in California energy and ancillary services markets."[5] ORA agrees with SDG&E's decision to separate MEC and MGCC, and it supports SDG&E's framework of calculating MGCC through the cost of a new CT minus energy rents, i.e. profits, and ancillary services ("A/S") rents. This is appropriate in a hybrid energy market such as California's wherein a new CT could sell electricity or

[2] This price comes from *The 2013-2014 Resource Adequacy Report*, p. 29 and is discussed further in section III.D.

[3] D.92-12-057 regarding a PG&E GRC says, "Marginal generation capacity costs are those incremental costs for generation which result from incremental load growth" at 26.3.

[4] See James Bonbright's *Principles of Public Utilities Ratemaking* at p. 475: "In the long run, peak demand usage presses against the capacity of the system and both operating *and* capacity costs are higher. Off-peak demand usage usually does *not* press against the system capacity, so only operating costs need be considered. Thus, capacity costs are caused primarily by the peak user."

[5] Jeffrey Shaugnessy, "Prepared Direct Testimony of Jeffrey J. Shaughnessy on Behalf of San Diego Gas and Electric Company in Support of Second Amended Application Chapter 7," Feb 9 2016, pp. JJS-7–8.

A/S into the market when prices are high, thus offsetting a portion of its capital costs.[6] It also continues a long history at the Commission of estimating MGCC through the deferral value of a CT adjusted downward for energy rents—a method accepted by all three Investor Owned Utilities ("IOUs").[7] SDG&E annualizes the cost of the CT through a Real Economic Carrying Charge ("RECC"), which calculates the annual revenue requirements required to pay for an asset and its subsequent replacements and compares them to the present worth of the asset and its replacements one year later (i.e. assumes deferral of operations for one year). ORA supports SDG&E's use of the RECC method here, as all three IOUs and ORA have used the same method to annualize the costs of a CT for MGCC in many previous General Rate Cases ("GRCs").[8]

However, an important point—and one that SDG&E fails to acknowledge—is that the Commission also has a long history of adjusting the value of MGCC downward during times of near-term surplus capacity. Throughout the 1990s, the Commission adjusted MGCC downward using an Energy Reliability Index ("ERI")—a value less than or equal to 1—and specifically multiplying it by the value of marginal capacity to get the MGCC value.[9] The value of the ERI would be less than one in instances when the system had near-term surplus capacity. Although this method fell out of practice during deregulation of California's electricity sector in the late 1990s, the economic principles underlying it are still valid. Since 2001, all MGCC values have arisen through settlements

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[6] Even in a situation where a new CT plant was owned by a utility and the utility chose to serve its customers rather than sell electricity or A/S into the market when prices were high, these rents would still represent an avoided cost to the utility and should be subtracted from the CT's costs.

[7] PG&E, A.13.04.012, "Chapter 2. Marginal Generation Costs," in *PG&E 2014, General Rate Case Phase II, Update/Errata Testimony Exhibit (PG&E-5) Volume 1 Marginal Costs* (2013), p. 2-3.

SCE, A.14.06.14, *Phase 2 of 2015 General Rate Case: Marginal Cost and Sales Forecast Proposals* (2014), p. 23.

[8] PG&E, A.13.04.012, "Chapter 2. Marginal Generation Costs," in *PG&E 2014 General Rate Case Phase II Update/Errata Testimony Exhibit (PG&E-5) Volume 1 Marginal Costs* (2013), p. 2-3.

SCE, A.14.06.14, *Phase 2 of 2015 General Rate Case: Marginal Cost and Sales Forecast Proposals* (2014), p. 22.

ORA, A.14.06.14, "Chapter 4: Marginal Generation Capacity Costs," in *Testimony on Southern California Edison's 2015 General Rate Case Phase II* (2015), p. 4-3.

[9] D.92-06-020, D.96-04-050. D.92-12-057 also notes that the "ERI-adjusted combustion turbine (CT) proxy method" was the method currently used by the Commission for PG&E's MGCC.

that—although some parties have proposed using the full annualized cost of a CT plant—have generally adopted values somewhat lower than the full costs of a CT. This stems from the Commission's thinking that the value of capacity should be discounted during times of capacity surplus. This position was clearly stated in the Decision for Resolution I.86-06-005, in which the Commission said that marginal costs should "be low in times of capacity surplus, rising to full cost when capacity is constrained."[10] It was also reiterated in several Decisions during the 1990's,[11] culminating in a Southern California Edison Company ("SCE") GRC Phase 2 Decision (D.96-04-050):

> Although Edison apparently believes we were misguided in our 1992 decision (RT at 7789-7790), we continue to find its arguments for an ERI of 1.0 to be unpersuasive. Moreover, Edison's preference to ignore short-term capacity conditions in the valuation of marginal generation costs is inconsistent with how we evaluate the capacity value of new resource additions, such as DSM [Demand Side Management]. (RT at 7792.) We adopt an ERI of 0.85…[12]

In the 1996 decision cited above, the Commission chose to discount the value of marginal generation costs based on the need to consider "short-term capacity conditions," i.e. conditions of near-term capacity surplus or scarcity, when valuing new resource additions.

The Commission's position is also in accord with mainstream economic theory, which holds that customers should only be charged the *present value* of marginal capacity if that capacity is needed at some point in the future. For example, in *The Economics of Regulation* Alfred Kahn describes a situation in which a utility must make lumpy investments in capacity in order to meet anticipated increases in peak demand (exactly the situation arising in our discussion of MGCC), inevitably resulting in near-

[10] I.86-06-005, D.92-12-058, 1992 Cal. PUC LEXIS 970 (Dec. 1992), p. 43.

[11] See D.90-07-055, Section III.C which argues that prices should take into account the timing of planned capacity additions (and thus would be lower during times of capacity surplus, which pushes the timing of capacity additions further into the future). Also see D.92-12-057 for a similar argument.

[12] D.96-04-050, Sec. 5.4.2.2.

term surplus capacity. Kahn asks, "What, in these circumstances, is the proper measure of marginal costs?" He answers his question as follows:

> …there is a strong economic case for letting prices rise and fall as demand shifts… in the presence of excess capacity, no matter how temporary, no business should be turned away that covers the SRMC [short run marginal cost] of supplying it.[13]

Here, Kahn's emphasis on short-run marginal costs, i.e. taking into consideration near-term capacity scarcity or surplus, is in accord with the Commission's emphasis on short-term conditions. Kahn then goes further in a footnote to describe how peak capacity costs can be attributed to users even in the absence of an immediate need for capacity:

> It might appear that no customer whose continued patronage would eventually require additions to capacity should ever be charged a price that completely excludes those capital costs; the economic ideal, it might appear, would be to include them, but *discounted back to the present value*, to reflect the fact that continued service of the customer in question would require their incurrence only sometime in the future.[14] [emphasis added]

The caveat "it might appear" refers to Kahn's subsequent statement that some customers may not in fact be responsible for marginal capacity costs if they drop out of the market before the company decides whether or not to purchase the additional capacity. Thus, it is largely irrelevant here. The most important point here is Kahn's central argument that customers should be charged the costs of future capacity additions *discounted back to the present value* (i.e. using the time value of money) if their current usage requires capacity to be needed sometime in the future. Thus, it is entirely consistent with Commission precedent and mainstream economic theory that MGCC should be discounted during times of near-term capacity surplus and customers should only be charged the present value of future capacity additions.

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[13] Alfred Kahn, *The Economics of Regulation* (1970), p. 104.

[14] *Ibid.*, p. 104, footnote 47.

III. DISCUSSION

ORA accepts SDG&E's conceptual framework of calculating MGCC through the cost of a new CT plant less energy and A/S rents, with three major exceptions:

1) SDG&E's MGCC should be based on the installation costs of an advanced CT due to their greater fuel efficiency, lower emissions, greater operational flexibility and lower costs;
2) SDG&E's MGCC should be adjusted downward by a 12% discount factor to reflect that marginal capacity will not be needed until at least 2019; and
3) The MGCC value should be adjusted upward by 15% to reflect the Resource Adequacy requirement for a 15–17% Planning Reserve Margin.

A. Installation Costs of the CT Plant Should be Based on an Advanced CT

SDG&E bases its MGCC calculations on the installation cost of a conventional CT plant using aeroderivative design, i.e. resembling the jet engine of a commercial airliner, and using General Electric ("GE") LM6000 gas turbines. While this is currently the most common conventional CT type in California, the California Energy Commission's ("CEC") *Estimated Cost of Renewable and Fossil Generation in California* report states, "In California, there is a growing tendency to build advanced versions of the aeroderivative CT units that provide greater fuel efficiency, reduced costs and reduced emissions."[15] The report assumes a 200 MW advanced CT plant using GE LMS100 turbines. These turbines use an intercooling system to take compressed air from the low-pressure chamber, cool it to an optimal temperature and redeliver it to the high-pressure chamber, thus reducing the work of compression and greatly increasing the turbine's thermal efficiency.[16] According to the report, advanced CTs require only 9,880 British

[15] California Energy Commission, *Estimated Cost of Renewable and Fossil Fuel Generation in California* (2014), p. 122, accessed at http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf.

[16] According to the report, the GE LMS100 can achieve thermal efficiency (the ratio of work output over heat input) of up to 44%, which is roughly 10% above other turbines in its size range. *Ibid*, p. 123.

thermal units ("Btu") of natural gas to produce 1 kWh of electricity (mid case) whereas conventional CTs require 10,585 Btu per kWh (mid case), and advanced CTs produce fewer emissions of criteria air pollutants and carbon dioxide, as shown below:[17]

Table 3-1. Emissions Factors of CT Technologies

Technology	**NO_X**	**V.O.C**	**CO**	**SO_X**	**PM10**	**CO_2**
	Power Plant Emissions Factors (lb./MWh)					
Conventional CT	0.279	0.054	0.368	0.013	0.134	1,239.29
Advanced CT	0.099	0.031	0.19	0.008	0.062	1,156.75

Advanced CTs' reduced emissions of carbon dioxide (6.7% less) is particularly important given California's goals to reduce its greenhouse gas emissions.[18] In addition, advanced CTs are being built in increasing numbers in California. For instance LMS100 turbines were used in a variety of recent installations, including: the Panoche Energy Center (400 MW capacity) in western Fresno County in 2009, the Sentinel Energy Project (800 MW) in Desert Hot Springs in 2013, the Walnut Creek Energy Park (500 MW) in 2013 and the Pio Pico Energy (300 MW) and Carlsbad Energy Center (500 MW), which will begin operation in SDG&E's service territory in 2017 and 2018 to meet local capacity requirements for 2018.[19] LMS100s can cold-start from 0 to 100 MW in less than 10

[17] Heat rate (Btu/kWh) data are from Table 49, *Ibid*, p. 131. Emissions table is derived from Tables 52 and 53, *Ibid*, pp. 134–135. V.O.C.–Volatile Organic Compounds; PM10–Particulate Matter with a diameter of 2.5 to 10 micrometers.

[18] Among other goals, California aims for a 20% reduction in GHGs below 1990 levels by 2020 and 80% by 2050. See Assembly Bill 32, Chapter 488, 2005–2006 Session of CA State Legislature (2006); Governor's Exec. Order No. S-3-05 (2005), accessible at https://www.gov.ca.gov/news.php?id=1861.

[19] California Energy Commission, Panoche Energy Center Power Plant Licensing Case, accessed at http://www.energy.ca.gov/sitingcases/panoche/index.html.

Thomas W. Overton, "CPV Sentinel Energy Project, Desert Hot Springs, California," *Power* (2014), accessed at http://www.powermag.com/cpv-sentinel-energy-project-desert-hot-springs-california/.

California Energy Commission, Walnut Creek Energy Park Power Plan Licensing Case, accessed at http://www.energy.ca.gov/sitingcases/walnutcreek/index.html.

California Energy Commission, Pio Pico Energy Center Power Plant Licensing Case, accessed at http://www.energy.ca.gov/sitingcases/piopico/index.html.

Also see D.14-06-053, which confirms that Pio Pico meets a 2018 LCR need.

Thomas W. Overton, "SDG&E and NRG Near Finish Line for Carlsbad Energy Center," *Power* (2014), p. 1, accessed at http://www.powermag.com/sdge-and-nrg-near-finish-line-for-carlsbad-energy-center/.

minutes (similar to the LM6000), can ramp up from half to full power in less than sixty seconds, exhibit high fuel efficiency even while operating at partial loads (and thus produce lower emissions) and have an unrestricted number of starts and stops per day—making them ideal for providing operational flexibility and integrating variable renewable energy resources.[20]

For the above stated reasons, ORA proposes to base SDG&E's MGCC on the installation cost of an advanced CT utilizing LMS100 turbines. The CEC report lists the installed cost of a 200 MW advanced CT as $1,069/kW (Mid Cost Case, Merchant Generator), which is lower than a conventional CT's installed cost of $1,316/kW (Mid Cost Case, IOU-Owned).[21] This difference can be found on Line 1 of Table 3-2, page 3-15. However, the CEC report also states in its description of CT plant instant costs, "The advanced CT case cost is based on very limited data for a different advanced gas turbine type."[22] While ORA recognizes that the advanced CT costs are based on very limited data, it highlights that the CEC did choose to include these costs in the report—unlike for other technologies in California such as the advanced Combined Cycle—and thus it is sufficient and valid data to use for analysis.[23] ORA has reviewed the report's list of CT plants and was only able to identify a single advanced CT, the Panoche Energy Center (400 MW). Although this is a large peaker plant, it is comparable in size to SDG&E's next two generation capacity additions—which are both advanced CTs—the Pio Pico Energy Center (300 MW) and Carlsbad Energy Center (500 MW). Thus, the CEC data provides an appropriate comparison for SDG&E's MGCC. Finally, the advanced CT has

[20] "GE announces orders for 10 LMS100 gas turbines," *Power Engineering* (2015), accessed at http://www.power-eng.com/articles/2015/07/ge-announces-orders-for-10-lms100-gas-turbines.html. GE, "LMS100 (50 HZ) Fact Sheet," powergen.gepower.com, accessed at https://powergen.gepower.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/LMS100-50-fact-sheet-2016.pdf

[21] California Energy Commission, *Estimated Cost of Renewable and Fossil Generation in California* (2015), p. 140.

[22] *Ibid.*, p. 136.

[23] The CEC report notes there is one advanced CC plant in California but it "provides insufficient data from which to estimate … costs" and therefore it is not included in the report. *Ibid*, p. 123.

lower fixed operations and maintenance costs of $25.24/kW-yr. (mid case) compared to a conventional CT's $27.44/kW-yr. (mid case), as shown on line 7 of Table 3-2.[24] Given all of the cost and operational benefits of the LMS100 versus the LM6000, it is reasonable to use the advanced CT as the basis for calculating MGCC.

B. SDG&E's MGCC Should be Estimated Based on the Value of a CT Installed in 2018 and Deferred to 2019

Second, SDG&E's MGCC should be based on the value of a CT plant installed in 2018 and deferred to 2019—which is the earliest possible year of marginal capacity need in SDG&E's service territory. The Commission determines the need for capacity additions through the biennial Long-Term Procurement Planning ("LTPP") proceeding, which covers a ten-year time horizon. The most recent LTPP proceeding to authorize any capacity procurements by SDG&E was the 2012 LTPP (R.12-03-014), which was organized into four "Tracks"—of which only Track 4 is relevant here.[25] The Track 4 Decision evaluates overall Local Capacity Requirement needs stemming from both the retirement of the San Onofre Nuclear Generation Stations (SONGS) and other Once-Through Cooling ("OTC") plants (D.14-03-004)[26] and authorizes SDG&E to procure between 500 and 800 MW of capacity by 2022. However, Section 3.2 states that "both SCE and SDG&E have sufficient supplies to meet projected demands in the SONGS service area through at least 2018, even with the unexpected early retirement of SONGS. Significant supplies have come online in recent years, while overall demand is lower than anticipated several years ago (due to both weakness in the economy and the success of

[24] *Ibid.*, p. 141.

[25] Track 1 addressed Local Capacity Requirements in all CPUC jurisdictions but did not authorize any procurements by SDG&E. Track 2, which focused on system reliability needs, was canceled due to an Assigned Commissioner and ALJ's Ruling dated September 16, 2013. Track 3 addressed long-term procurement rules but did not authorize any additional procurements.

[26] See the paragraph beginning, "In this Track 4 proceeding…" D.14-03-004, pp. 23–24. The retirement of OTC plants is due to State Water Resources Control Board regulations, *Ibid.*, p. 23.

demand side management and energy efficiency programs)."[27] This clearly implies that capacity may be needed as early as 2018, and it establishes conditions of near-term surplus capacity due to "significant supplies" having come online, lower-than-anticipated demand and the success of demand side management and energy efficiency.[28] The Decision indicates 2018 as the near year of capacity need. However, it does not address the issue of whether the capacity needed in 2018 is *marginal* capacity. This is a crucial point, because the Commission has clearly stated that marginal costs should only include costs arising from an incremental unit of output:

> Marginal costs may be defined as the change in total cost which results from a change in output. The result of using marginal cost in rate setting is that the rate equals the cost of producing one more unit, or the savings from producing one less unit.[29]

MGCC should only be based on the cost of providing capacity to meet an incremental unit of demand. New capacity that is needed in the absence of SONGS, however, may simply be replacement capacity needed to meet already existing demand. A more careful consideration of this matter requires looking at the California Independent System Operator Corporation's ("CAISO") Opening Testimony in the Track 4 proceeding.

The Opening Testimony of CAISO Expert Witness Robert Sparks shows that SDG&E's capacity need in 2018 is in fact for replacement of SONGS and OTC plants rather than marginal capacity, because the replacement capacity is not being procured to respond to increased or marginal demand from customers.[30] Mr. Sparks provides the results of power flow studies for 2018 and 2022 for the SONGS study area. His testimony presents two tables that both compare capacity needs in 2018 to 2022, one assuming a

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[27] D.14-03-004, p. 23. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF.

[28] The finding that capacity may be needed in SDG&E's service territory as early as 2018 is reinforced in D.15-11-024, Orders 2, 8 and 9, and D.15-05-051, Conclusion of Law 5.

[29] OII–Marginal Cost Methodology, D.92749, 5 CPUC2d 620, 1981 Cal. PUC LEXIS 597, p. *3.

[30] Robert Sparks, "Track 4 Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation," accessed at http://www.caiso.com/Documents/Aug5_2013_Track_4_Testimony_RobertSparks_R12-03-014.pdf

80%/20% capacity split between the L.A. Basin and San Diego area and the other a 67%/33% split (the latter of which has been reproduced below):[31]

Figure 3-1. Results of CAISO Power Flow Studies

Table 12 – Summary of Additional Resource Additions in San Diego (in the – Without SONGS Scenarios)

	2018 - Without SONGS				2022 - Without SONGS (Incremental Need)			Total Resource Needs (MW)
Area	OTC Replacement Assumptions (MW)	Additional Resource Assumptions (MW)	Extension of Non-OTC Aging Generation Assumptions (MW)	Repowering of Non-OTC Generation Assumptions (MW)	OTC Replacement Assumptions (MW)	Retirement of Non-OTC Aging Generation Assumptions (MW)	Additional Resource Assumptions (MW)	
Southwestern LA Basin	0	0	0	260	2462	0	300	3022
Northwestern LA Basin	0	0	0	0	0	0	0	0
Eastern LA Basin	0	0	640	0	0	-640	0	0
Subtotal LA Basin	*900*				*2122*			*3022*
Northwest San Diego	520	0	0	0	0	0	565	1085
Southwest San Diego	0	100	0	0	0	0	0	100
Southeast San Diego	0	300	0	0	0	0	0	300
Subtotal San Diego	*920*				*565*			*1485*
Total SONGS Study Area	*1820*				*2687*			*4507*

As can be seen from the 2018 scenario, most of the capacity needed in 2018 is in fact for the replacement or extension of OTC or other existing plants (see columns 1, 3 and 4—all of which are replacement, extension or repowering of existing capacity, and none of which qualify as marginal capacity). The San Diego area does show 400 MW of Additional Resource Assumptions, or new capacity "from additional conventional resources, or preferred resources."[32] However, SDG&E held a 20% share in SONGS and drew 430 MW of power from it while it was in operation.[33] Thus, the total amount of new

[31] *Ibid.*, Table 12–Summary of Additional Resource Additions in San Diego (in the Without Songs Scenarios).

[32] *Ibid.*, p. 4, 18.

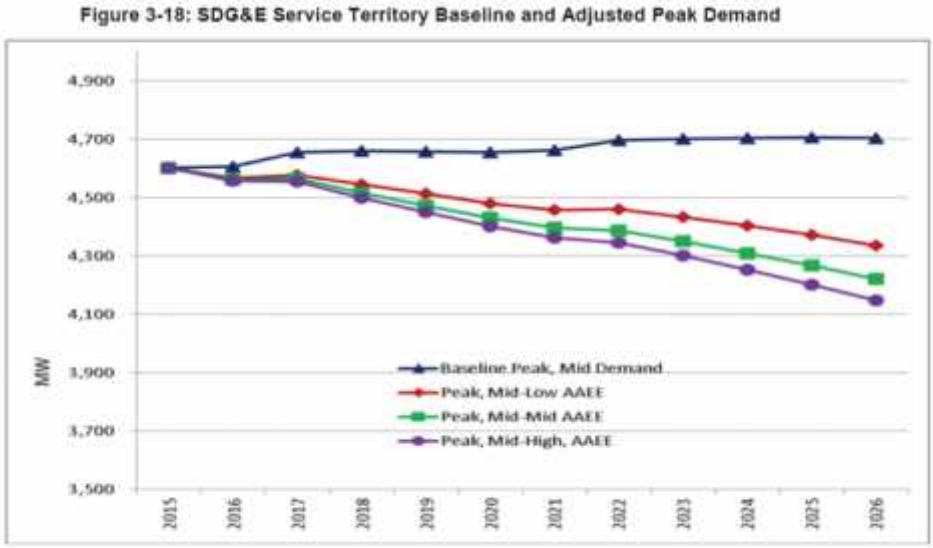
[33] See http://www.dra.ca.gov/SONGS.aspx.

Environmental Science Associates, Section 2.3.3., *Initial Study for San Diego Gas & Electric Company's Application No. 97-12-039*, p. 239, accessed at http://www.cpuc.ca.gov/Environment/info/esa/divest-sdge/chapters/00_toc.htm (click on chapter 2 pdf).

capacity needed in 2018 does not even equal the amount of power that SONGS previously provided to the San Diego area, and it cannot be said to be marginal capacity. It is only if this new capacity were to exceed 430 MW that it could be considered marginal capacity. By 2022 the total cumulative new capacity needed in SDG&E's service territory is 100 + 300 + 565 = 965 MW, which far exceeds the amount previously provided by SONGS. Since there is clearly a marginal capacity need in 2022 but there is no such need in 2018, ORA chooses 2019 as the earliest year that marginal capacity *may* be needed in SDG&E's service territory.

Finally, to underscore the lack of any immediate need for marginal capacity in SDG&E's service territory, ORA highlights the CEC's most recent revised electricity demand forecast. This forecast shows that SDG&E's peak demand is likely to *decrease* over time once additional achievable energy efficiency ("AAEE") is included:[34]

Figure 3-2. SDG&E Peak Demand (Baseline & AAEE-Adjusted)



Source: California Energy Commission, Demand Analysis Office, 2015

According to the CEC, AAEE includes energy efficiency savings that are "likely to occur, including impacts from future updates of building codes and appliance standards

[34] CEC, *California Energy Demand: 2016-2026 Revised Electricity Demand Forecast*, p. 69.

and utility efficiency programs expected to be implemented after 2015."[35] As can be seen above, in all three scenarios in which AAEE is included peak demand decreases over time, and thus it is unlikely that any marginal generation capacity will be needed to meet incremental peak demand in the near term.[36] The Mid-Low AAEE curve (red) has been adopted by the CEC, CAISO and CPUC for local studies and the Mid-Mid AAEE curve (green) has been adopted for the 2016-2017 Transmission Planning Process and LTPP.[37]

Based on its finding of a 2019 year of marginal capacity need, ORA proposes that SDG&E's MGCC value should be based on the cost of a CT plant installed in 2018 and deferred to 2019 (following the RECC method, which assumes deferral of operations for one year). Escalating the costs of a CT plant to 2018 dollars and finding the present value of these costs (using a 7.79% discount rate, the same that SDG&E uses) yields a CT cost that is 12% lower than the original value, or $79.85/kW-yr. compared to $90.27/kW-yr.[38] This adjustment can be found on Line 15 of Table 3-2 below. SDG&E proposes no such adjustment for the time value of money, which ORA finds to be a mistake and one that assumes marginal generation capacity is needed immediately—when in fact it is not needed until at least 2019.

C. SDG&E's MGCC Should Include a 15% Resource Adequacy Adder to Reflect RA Requirements

ORA highlights that SDG&E omits a 15% Resource Adequacy ("RA") adder from its proposed MGCC value. It is necessary to include an RA adder in MGCC because the Commission's Resource Adequacy proceeding requires that each Load Serving Entity ("LSE") procure sufficient capacity to meet its customers' forecasted load plus a 15–17%

[35] *Ibid.*, p. 54.

[36] All the scenarios are based on the CEC's Mid Demand forecast, which is referred to by the first word in the phrases "Mid-Low," "Mid-Mid," etc. The second word refers to the level of AAEE.

[37] California Energy Commission, *2015 IEPR: Integrated Energy Policy Report* (Feb 24, 2016), p. 144.

[38] The discount rate comes from SDG&E's Cost of Capital proceeding, D.12-12-034, Conclusion of Law 22. It also matches the Rate of Return (ROR) used by SDG&E in its RECC method.

Planning Reserve Margin ("PRM").[39] In effect, this means that for each additional 1 kW of customer demand that a utility faces, it must procure at least 1.15 kW of additional generation capacity. Thus, ORA has included a 15% RA adder in its MGCC calculation, which can be found on line 16 of Table 3-2. This proposed 15% RA adder is not new, as the Commission adopted a 1.15 "Capacity Response Ratio" in a 1996 SCE GRC Phase 2 Decision.[40]

D. San Diego–Imperial Valley's Weighted Average RA Capacity Market Price of $48.96/kW-year Supports ORA's Lowered MGCC Value

Finally, ORA's proposed MGCC value of $91.83/kW-yr. is closer than SDG&E's to the observed RA capacity market price of $48.96/kW-yr. for San Diego-Imperial Valley. Observed RA capacity market prices can be found in the annual Resource Adequacy Report released by the Energy Division ("ED"). The most recent *2013–2014 Resource Adequacy Report* compiles data from 11 CPUC-jurisdictional LSEs (including the 3 IOUs) on all monthly capacity contract prices for 2013–2017.[41] The capacity prices are weighed by the number of MW in each contract. According to the report, the weighted average RA capacity price for South of Pass-26 ("SP-26") is $3.60/kW-month, or $43.30/kW-yr., for 2013–2017 and it is *$4.08/kW-month*, or *$48.96/kW-yr.*, for the San

[39] The RA proceeding requires LSEs to meet Local, System and Flexible RA requirements. It is as part of their System RA requirements that each LSE must meet its CEC adjusted demand forecast plus 15%. For more information, see http://www.cpuc.ca.gov/RA/.

D.04-01-050 also discusses the 15–17% PRM as foundational to the RA framework, pp. 11, 21–22.

[40] D.96-04-050.

[41] ED estimates that the data covers 25% of all RA capacity procured in 2013, 25% of all RA capacity in 2014, 24% in 2015, 14% in 2016 and 6% in 2017. The annual percentages are calculated by dividing the sum of reported monthly capacity contracts (MW) by the sum of monthly RA requirements net CAM, RMR and DR allocations for each year. The sum of monthly RA requirements for 2014 is used as a proxy for total RA requirements for 2015, 2016 and 2017 as well. The data includes contracts for capacity bought and sold, so there is some possibility for double counting.

CPUC Energy Division, *2013-2014 Resource Adequacy Report* (2015), p. 23, accessed at http://www.cpuc.ca.gov/RA/

Diego-Imperial Valley local area ("SD-IV") for 2013–2017.[42] This is far below SDG&E's proposed MGCC value of $118.16/kW-yr., and it provides evidence that capacity can be procured at a price well below the full annualized cost of a new CT plant and that the value of MGCC should be discounted. RA capacity prices and MGCC are not perfect equivalents, as the RA prices include *all* capacity (existing and new) that is needed to meet forecasted demand plus 15% whereas MGCC is limited to capacity that is truly marginal, i.e. needed to meet an *incremental unit* of peak demand. Therefore, MGCC is a smaller subset of all RA capacity. However, the low RA capacity prices for SP-26 and SD-IV provide strong signals that the cost of procuring generation capacity to meet reliability requirements is lower than the full annualized cost of a CT minus rents, and thus MGCC should be lowered. Finally, ORA provides a full comparison of all the steps in SDG&E's and ORA's MGCC calculations in Table 3-2 below.

[42] *Ibid.*, Table 12. Capacity Prices by Local Area, 2013-2017, p. 28.

Table 3-2. SDG&E's and ORA's Proposed MGCC Values

Marginal Generation Capacity Costs	**SDG&E**	**ORA**
1. Installed Cost of CT Plant* (2013 $/kW) *SDG&E uses a conventional CT plant whereas ORA proposes the use of an advanced CT plant	$1,316.00	$1,069.00
2. Real Economic Carrying Charge (RECC)	9.35%	9.35%
3. Annualized CT Installed Cost (1 * 2) (2013 $/kW-yr.)	$123.06	$99.96
4. General Plant Loader (line 3 * 2.27%)	$2.79	$2.26
5. Working Capital Loader (line 3 * 0.76%)	$0.93	$0.76
6. A&G on General Plant Loading ((line 3 + 4) * 1.82%)	$2.29	$1.86
7. Fixed Operations & Maintenance (O&M) Costs	$27.44	$25.24
8. Incremental Capacity Cost (2013 $/kW-yr.) (line 3+4+5+6+7)	**$156.51**	**$130.08**
9. Incremental Capacity Cost Escalated to 2016 $/kW-yr. (1.84% inflation rate)	**$165.29**	**$137.40**
10. Energy Rents (2016 $/kW-yr)	$43.69	$43.69
11. Ancillary Services Rents (2016 $/kW-yr.)	$3.44	$3.44
12. Incremental Capacity Cost (2016 $/kW-yr.) (Line 9-10-11)	**$118.16**	**$90.27**
13. Year of Marginal Capacity Need	2016	2019
14. Discount Factor for the Time Value of Money (1.84% Inflation Rate, 7.79% Discount Rate)	-	.88
15. Time-Adjusted Incremental Capacity Cost (2016 $/kW-yr.) (line 12 * 14)	**$118.16**	**$79.85**
16. RA Planning Reserve Margin (PRM) Adder	-	15%
17. Marginal Generation Capacity Cost (2016 $/kW-yr.)	**$118.16**	**$91.83**

IV. MGCC REVENUE ALLOCATION—USE OF AN ALL TOP LOLP HOURS METHOD

MGCC revenue allocation is an important component of marginal commodity cost (or marginal generation cost) revenue allocation, which is discussed more fully in Chapter 6 of ORA's testimony.[43] SDG&E uses a Top 100 Loss Of Load Expectation ("LOLE") hours method to assign MGCC revenue allocation. Typically, LOLE refers to

[43] ORA uses the terms "marginal generation costs" and "marginal commodity costs" interchangeably, i.e. the sum of MGCC and MEC.

the number of loss of load event days per year or per ten years, but SDG&E defines it as "the probability of not meeting load in an hour when key system variables are analyzed stochastically"—i.e. Loss of Load Probability ("LOLP").[44] For clarity's sake and to show that ORA's proposed method is comparable to SDG&E's (they both in fact rely on LOLP), ORA will refer to SDG&E's relative LOLE values as relative LOLP's. Therefore, SDG&E's Top 100 LOLP Hours method entails running an LOLP simulation to identify the top 100 hours in the year with the highest relative LOLP's and multiplying each customer class' hourly bundled load during those hours by those hours' relative LOLP's.[45] Each class' hourly LOLP-weighted loads are then summed for all 100 hours and its proportion of the total LOLP-weighted load determines the MGCC revenue allocation.[46] ORA proposes to expand this method to include all the top LOLP hours in the year in order to fully account for all the relative LOLP occurring over the entire year.

Synapse ran a loss of load simulation using SCE's spreadsheet-based model and assigned marginal generation capacity costs to all hours with relative LOLP greater than 0 (an All top LOLP hours method). The results of this modeling are presented in chapter 4 of ORA's testimony.[47] ORA takes the results of Synapse's analysis and, in order to increase the percentage of relative LOLP accounted for by the MGCC revenue allocation, adopts the All top LOLP hours method for MGCC revenue allocation as well. ORA notes that SDG&E's Top 100 LOLE hours method only covers 62% of the total relative LOLP

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[44] A.15-04-012, Robert B. Anderson, "Chapter 3 on Behalf of San Diego Gas & Electric Company," p. RBA-15.

[45] "Relative" LOLP refers to LOLP that has been scaled up so that all the values in the year sum to 1. Specifically, SDG&E used the Ventyx Planning and Risk Model, a spreadsheet-based "production cost model" tailored to the SDG&E system. This model simulates hourly least-cost dispatch of generation units—incorporating generation, transmission, fuel and other constraints. Running the model multiple times results in a probability distribution of the hours with the highest relative LOLP's. See Testimony of SDG&E witness Robert Anderson, Chapter 3, p. RBA-15.

[46] For further details, see the workpaper of SDG&E witness Jeffrey Shaugnessy A.15-04-012 Chapter 7 Workpaper MGCC (REDACTED) – first tab, columns W through AA. The sum of each class' LOLP-weighted load is listed on the second tab, line 8.

[47] SCE's LOLE model is an hourly spreadsheet-based model that is comparable to SDG&E's spreadsheet-based Ventyx model. Synapse weighted ORA's MGCC value by the relative LOLP values for each hour in the year, and then summed the results with its MEC values. The resulting hourly marginal costs (LOLP-weighted MGCC + MEC) informed the development of ORA's TOU time periods.

for the year—i.e. it assigns revenue based on only 62% of the probability of outages over the year.[48] Expanding the top hours to include all hours in which LOLP is greater than 0 (2,582 hours according to Synapse's analysis) would cover 100% of the total relative LOLP for the entire year.[49] ORA's method is superior because it is based on a wider set of hours that fully accounts for the total relative LOLP occurring over the year rather than being arbitrarily limited to the top 100 hours. ORA's proposed method results in the following changes to the MGCC revenue allocation:[50]

Table 3-3. SDG&E's & ORA's Proposed MGCC Revenue Allocations

	Residential	Sm. Comm.	M/L C&I	Agricultural	Lighting	Total
SDG&E	54.67%	10.75%	32.97%	1.25%	0.36%	100%
ORA	51.11%	11.72%	35.40%	1.46%	0.31%	100%

The details of how this affects the revenue requirements assigned to each class are discussed more fully in chapter 6. Finally, use of all top LOLP hours results in the following changes to the MGCC allocation to TOU periods and seasons:[51]

Table 3-4. MGCC Allocation to TOU Periods

LOLP % by TOU Periods

SDG&E: (Top 100 Hrs Approach)	Summer	Winter	**ORA:** (All Top LOLP Hrs)	Summer	Winter
***On-Peak*:** 4 - 9pm Daily	76.7%	0.0%	***On-Peak*:** 4 - 9pm Weekdays	44.1%	9.1%
Off-Peak: All Other Hours	23.3%	0.0%	***Off-Peak:*** All Other Hours	41.3%	5.5%
***Super Off-Peak*:** 12am-6am weekdays and 12pm-2pm weekends/holidays	0.0%	0.0%	***Super Off-Peak*:** None	0.0%	0.0%
Total:	100.0%	0.0%	***Total:***	85.4%	14.6%

[48] See SDG&E's workpaper A.15-04-012 Chapter 7 Workpaper 2016 LOLE Summary, first tab cell O6.

[49] See ORA's workpaper ORA Testimony Chapter 4 LOLP (Modeling Results), "Summary" tab.

[50] Percentages are determined using each class' load compared to the total LOLP-weighted load. For each class' load, see SDG&E's Chapter 7 Workpaper MGCC Allocation (REDACTED), second tab, row 17, and see ORA's workpaper ORA Testimony Chapter 3 Marginal Generation (Commodity) Capacity Costs Allocation (SDG&E Workpaper), "Summary by Class (Scenario 2)" tab, row 65.

[51] See ORA's workpaper: ORA Testimony Chapter 3 Marginal Generation (Commodity) Capacity Costs Allocation (SDG&E Workpaper), third tab.

ORA's allocation is based on all top LOLP hours (100% of relative LOLP), whereas SDG&E's shows the allocation of relative LOLP into TOU periods *based on only the top 100 LOLP hours* (62% of total relative LOLP). Thus, the tables do not provide a perfect apples-to-apples comparison (and SDG&E's would likely show a lower summer On-Peak period allocation if it used all relative LOLP over the entire year). In addition, ORA's table assumes a four month summer (July 1 through October 31) whereas SDG&E's assumes a six month summer (May through October).[52]

At first glance, it appears that the percentage allocated to the summer On-Peak period is much lower for ORA's allocation than for SDG&E's, but this is a natural result of ORA's shortening the summer On-Peak period to less hours (due to the four month summer)—in addition to the exclusion of weekend hours from the On-Peak period. ORA's scenario still allocates a large portion of LOLP (44.1%) to relatively few summer On-Peak hours (435 hours or 15% of total summer hours) and will result in a sufficiently large price signal being sent to customers during summer On-Peak hours. In addition, ORA allocates a higher percentage of LOLP to winter. This is partly due to its longer, eight-month winter season, and it is also due to the fact that ORA's All top LOLP hours method captures the relative LOLP that occurs in traditional winter months. Thus, ORA's All top LOLP hours method is a more accurate method for allocating MGCC to TOU periods that fully encompasses all the relative LOLP over the entire year.

V. CONCLUSION

The Commission should adopt ORA's proposed marginal generation capacity costs, which include the following modifications to SDG&E's proposal: 1) the choice of an advanced CT for the CT plant installation costs, 2) a 12% downward adjustment for the time value of money to reflect the fact that 2019 is the earliest possible year of marginal capacity need, and 3) the inclusion of a 15% RA adder due to RA Planning

[52] ORA chooses a four month summer based on Synapse's finding that capacity cost concerns indicate a shorter summer period. See Chapter 4 of ORA's testimony.

Reserve Margin requirements. The weighted average RA capacity market price of $48.95/kW-yr. for San Diego-Imperial Valley for 2013–2017 supports choosing a lowered MGCC value such as ORA's in order to reflect short-term market conditions.

The Commission should adopt ORA's proposed MGCC value in order to reflect changes in plant technologies and near-term conditions of capacity surplus. Lastly the Commission should adopt an All top LOLP hours method, because it covers a greater percentage of the total loss of load probability over the entire year and is thus a more accurate way of allocating MGCC revenue.

CHAPTER 4

MARGINAL GENERATION COSTS

ROBERT M. FAGAN AND PATRICK LUCKOW
SYNAPSE ENERGY ECONOMICS
ON BEHALF OF THE
OFFICE OF RATEPAYER ADVOCATES ("ORA")

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CHAPTER 4

MARGINAL GENERATION COSTS

SYNAPSE ENERGY ECONOMICS

I. Introduction and Summary of Findings

Purpose

What is the purpose of this testimony?

The purpose of this testimony is to present results of PLEXOS[1] production cost simulation modeling and relative loss-of-load-expectation ("LOLE") modeling[2] that informs the estimation of hourly marginal generation costs ("MGC") for San Diego Gas and Electric ("SDG&E") for Phase 2 of the General Rate Case ("GRC") proceeding. Our findings support the California Office of Ratepayer Advocates' ("ORA's") recommended Time-of-Use ("TOU") periods applicable for SDG&E ratepayers for at least five years.[3] We also present comparisons between our results and the marginal energy costs ("MEC") estimates made by SDG&E for 2016, explain how our LOLE modeling and its application to develop an allocation of marginal capacity costs ("MCC") differs from SDG&E's application of their own LOLE modeling to the top 100 load hours, and discuss our overall findings.

Marginal generation costs are expressed as hourly costs composed of the combination of MEC and MCCs. We estimate wholesale hourly marginal energy costs for 2016 and 2020 using the PLEXOS model.

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[1] PLEXOS is Energy Exemplar's production cost simulation modeling tool. Synapse licenses PLEXOS from Energy Exemplar and performs production cost modeling simulations.

[2] Synapse used the LOLE model provided by Southern California Edison ("SCE") in response to discovery in the Pacific Gas and Electric Rate Design Window proceeding (A.14-11-014 PGE-SCE-001 Q.01 Response). SCE had used this spreadsheet model in its GRC Phase 2 Marginal Cost proposal (A.14-06-014, June 20, 2014). Synapse used the "shell" provided by SCE, and used its own input assumptions for resources and loads for the SDG&E area, and for the California Independent System Operator ("CAISO") region as a whole.

[3] It is our understanding that AB 327 guidance indicates that TOU periods should be appropriate for use over at least five years.

Hourly marginal capacity costs are estimated based on ORA's estimate of fixed costs for a new peaking resource, and the allocation of those costs generally to high-use hours when resource adequacy is tightest, based on the results of Synapse runs of the LOLE model.

The LOLE model estimates ***relative*** loss-of-load across the hours of the year; it is not an absolute indicator of loss of load expectation. Its purpose is limited to apportioning marginal capacity costs across certain hours of the year.

We execute the LOLE model for two annual time periods, 2016 and 2020; and for two different system zonal topography configurations, 1) SDG&E system, with imports from surrounding areas, and 2) the overall California Independent System Operator ("CAISO") system, with imports from adjacent regions. These four benchmarks for LOLE patterns will help to assess the robustness of any resulting selection of TOU periods based on MGC modeling, since the MCC allocation resulting from the LOLE model has a significant impact on MGC patterns, and thus informs TOU period consideration.

The estimated hourly MGC costs (comprised of hourly MEC plus hourly-allocated MCC) are averaged across seasonal and time-of-day periods to produce aggregate, or average, TOU-based marginal generation costs. We also present a comparison of our estimated marginal energy costs to SDG&E's 2016 marginal energy costs as estimated in SDG&E's GRC 2 Direct (February 2016) testimonies. We briefly compare our 2020 MGC results to SDG&E's Order Institute Rulemaking ("OIR") TOU Supplemental (April 2016) testimony on 2021 MGC.[4] We discuss the implications of the marginal generation costs for SDG&E's proposed TOU periods.

[4]SDG&E April 2016, Testimony and Workpapers of 1) Anderson, and 2) Shaughnessy. April 29, 2016 Supplemental Information Filing of San Diego Gas & Electric Company (U 902 E) for OIR TOU R.15-12-012.

Summary of Findings and Observations

Please summarize your key findings.

Our summary findings are listed below, based on a review of the marginal generation costs (in total MGC, and by component MEC and MCC) as presented in our monthly/hourly heat maps (in the following section), and summary MGC, MEC and MCC costs by period (Tables 4-1 and 4-2).

1. **4 PM to 9 PM Weekdays Peak Period**. ORA defines the TOU periods primarily based on grouping hours with similar hourly marginal costs into the same TOU period.[5] Synapse modeling supports an on-peak period of 4 PM to 9 PM during non-holiday weekdays, since marginal costs in the 4 PM to 9 PM period are generally higher during non-holiday weekday periods than weekend periods (this is somewhat less so for July and August). This is the case for a period of time that would extend from early 2017[6] to at least 2020, based on Synapse modeling of both marginal energy and marginal capacity costs for 2016 and 2020.

   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).

   recommends

2. **No Super Off-Peak Period Merited, Except Possibly for Spring Daytime Hours Only**. Our modeling does not support SDG&E's proposal for a super-off-peak that extends overnight (midnight to 6 AM) on all days, and through 2 PM on weekends. We find in general overnight prices (i.e., marginal energy costs) are

[5] In our modeling we make no assumptions on customer behavioral response to any particular TOU period that may be implemented.

[6] Our understanding is that any new TOU periods or rates that result from this GRC Phase 2 would not be implemented until early 2017.

equal to, or higher than, non-peak period daytime prices. Our modeling can support a multiple season consideration of a super off-peak period of 10 AM to 4 PM for March, April, and May, commensurate with relatively low load and high solar resource output. However, ORA also considers administrative feasibility and customer understanding, as further described in Chapter 6. Therefore, we recommend a single off-peak period for all other hours.

3. **MGC, MEC, MCC Summary Results by Year, Season and Period**. Tables 4-1 and 4-2 below summarize the results of our modeling of MGC and its component MEC and MCC, including the effect of using an RPS adder to the MEC. They contains data for 2016 and 2020, and compare two different seasonal definitions: 6 months summer (May to October), and 4 months summer (July to October). For both tables, on-peak hours are defined as 4 PM to 9 PM non-holiday weekdays (all year), and all other hours are off-peak. The tables include potential spring super-off-peak hours in the tabulation of the off-peak period averages.

The marginal generation cost variation across the seasons and across on and off-peak periods will affect the ultimate rate differentials seen by customers. While we recommend peak TOU periods remain the same all year, since the hour-to-hour patterns of prices exhibit similar time-based differences in both summer and winter, the ratio of on-peak to off-peak marginal generation costs is different between summer and winter periods (owing to the predominance of summertime allocation of marginal capacity costs).[7] As seen in Tables 4-1 and 4-2, average MGC ratios between on-peak and off-peak periods vary between the summer and the winter period. The choice of 4-month or 6-month summer season affects the on-peak/off-peak ratios for summer period MGC, but not for winter period (since little MCC is allocated in the winter). Marginal *energy* cost variation is minimal

[7] We note if "flexibility" concerns arise for sunset periods during the winter season, it becomes reasonable to allocate more of the marginal capacity costs to these winter periods, lessening the on-peak/off-peak MGC differential that exists between summer and winter seasons.

when considering the effect of a 4-month or a 6-month summer season. Marginal energy costs also exhibit minimal variation between summer and winter periods, for 2016 and 2020.

Table 4-1. 2016 Marginal Generation Costs

2016 Summer	Summer = May-October			Summer = July-October		
$/MWh, $2016	**MEC**	**MCC**	**MGC**	**MEC**	**MCC**	**MGC**
On-Peak	51.6	75.0	126.6	53.0	112.7	165.7
Off-Peak	42.4	8.4	50.9	44.0	11.7	55.6
Ratio On/Off Pk	1.2	8.9	2.5	1.2	9.6	3.0
2016 Winter						
$/MWh, $2016	**MEC**	**MCC**	**MGC**	**MEC**	**MCC**	**MGC**
On-Peak	51.4	13.5	64.9	50.7	10.2	61.0
Off-Peak	41.5	0.6	42.2	41.0	0.9	41.9
Ratio On/Off Pk	1.2	21.6	1.5	1.2	11.0	1.5

On-Peak Hours = Non-Holiday Weekdays, 4PM-9PM, Off Peak Hours all else. MCC allocation based on all-hours LOLE. RPS adder included.

Table 4-2. 2020 Marginal Generation Costs

2020 Summer	Summer = May-October			Summer = July-October		
$/MWh, $2016	**MEC**	**MCC**	**MGC**	**MEC**	**MCC**	**MGC**
On-Peak	58.7	76.8	135.5	60.1	113.9	174.0
Off-Peak	48.4	8.9	57.3	50.9	12.8	63.7
Ratio On/Off Pk	1.2	8.6	2.4	1.2	8.9	2.7
2020 Winter						
$/MWh, $2016	**MEC**	**MCC**	**MGC**	**MEC**	**MCC**	**MGC**
On-Peak	58.1	6.3	64.4	57.5	4.9	62.4
Off-Peak	46.8	0.9	47.6	45.9	0.9	46.8
Ratio On/Off Pk	1.2	7.1	1.4	1.3	5.2	1.3

On-Peak Hours = Non-Holiday Weekdays, 4PM-9PM, Off Peak Hours all else. MCC allocation based on all-hours LOLE. RPS adder included.

4. **LOLE Results**. Synapse's LOLE modeling results, which are translated into marginal capacity costs (MCC) as seen in Tables 4-1 and 4-2 above, and in the heat maps in the following section, indicate that the greatest relative loss of load expectation occurs during July through September in 2016, and July through October in 2020, and additional winter month MCC in both years (based on our preferred SDG&E regional configuration for assessing LOLE). When considering the CAISO region as a whole, LOLE occurs only in July at the peakiest period of the year for the entire region. We discuss this later in the testimony.

For the SDG&E region, the LOLE findings show greatest relative LOLE during the summer period, later afternoon and early evening hours, for 2016 and 2020 (see MCC heat maps in the next section). These findings generally support SDG&E's proposal to shift TOU hours to later in the day when considering the marginal costs of capacity – essentially, the potential need for new capacity arises primarily from usage during the later afternoon and early evening summer hours. While the LOLE model shows some fraction of relative LOLE in non-summer months (particularly in the hours around and after sunset) and our allocation of a proportionate share of marginal capacity costs to these non-summer periods follows from this (and is included in the MCC values seen in Tables 4-1 and 4-2), dominance of LOLE occurrence during the summer months suggests the importance of allocating much of the marginal capacity costs to these time periods.[8]

5. **4-Month vs. 6-Month Summer Season**. Our results indicate little difference in marginal energy cost patterns over a 4-month vs. a 6-month summer season definition, but the marginal capacity cost differences point towards a 4-month summer season, since so little of the MCC appears in the months of May and June.

[8] We note that this finding was supported, somewhat, by the results of the modeling conducted in the 2014 LTPP docket (R.13-12-010) and in Track 4 of the 2012 LTPP docket (R.12-03-014), and in CAISO's results presented in the OIR TOU docket (R.15-12-012, January 22, 2016).

6. **SDG&E vs. Synapse MEC Modeling**. We compared our summary 2016 marginal energy cost modeling results to SDG&E's marginal energy cost modeling results. The comparison is shown in Table 4-3 below, inclusive of the RPS adder to the wholesale energy prices. SDG&E did not model the year 2020 for this GRC Phase 2, thus our direct comparisons between Synapse and SDG&E results are only for 2016.[9] For 2016, different modeling methodologies (between Synapse and SDG&E) and input assumptions likely explain the differences in relative MEC across the hours of the day, and across the months. The table shows Synapse-computed MEC using the same May-October definition as SDG&E, and shows the MEC with potential super off-peak hours included as part of overall off-peak hours, and separately. When potential super off-peak hours are separated out, the average MEC for other off-peak hours increases slightly. The overall differences are relatively small, but our modeling does show lower overall average prices during summer, and off-peak winter; and slightly higher prices during on-peak winter. The overall hourly pattern of prices between our modeling and SDG&E's modeling is similar.

Table 4-3. Comparison Between SDG&E and Synapse Marginal Energy Cost Results, 2016

Summer 2016, $/MWh	SDG&E	Synapse (May–October)	Synapse (May–Oct) with Super Off-Peak Hours
On Peak	53.4	51.6	51.6
Off-Peak	44.9	42.4	42.8
Super Off Peak	37.0		35.2
Winter 2016, $/MWh			
On Peak	50.6	51.4	51.4
Off-Peak	44.6	41.5	42.5
Super Off Peak	38.7		32.6

Notes: Peak is 4-9 PM weekdays, Super Off-Peak is March-May, 10AM-4PM (for Synapse); and Midnight-6AM (weekdays) and midnight-2PM (weekends) for SDG&E (all months). Summer months are May-October. RPS adder included.

[9] We compare, in the next section, SDG&E's 2021 MGC estimates provided in R.15-12-012 (April 29, 2016 filing) to our 2020 MGC estimates.

Please summarize your overall observations on marginal generation cost and TOU period issues.

Overlaying MCC and MEC to create MGC highlights the summer peak period cost differences, but the magnitude of resulting differences between summer and winter MGC, and on-peak and off-peak MGC depends on how you allocate and value any needed capacity. And this allocation and valuation process is not an exact science; for example, our results include little allocation of MCC into winter periods, thus exacerbating summer/winter rate differentials, though more careful consideration of winter flexibility needs could shift more of the capacity allocation to winter periods.

Energy price patterns themselves clearly point towards a need to shift the peak period to later afternoon/early evening, all year long, and thus even without considering the MCC allocative effect, the need for an on-peak period change to roughly 4 PM to 9 PM is well established.[10]

Super off-peak periods are supported only for a limited number of daytime, spring hours.[11] The data and analysis do not support overnight super off-peak period designation at this time, for either 2016 or 2020.

Using LOLE modeling distributes MCC over more than just the top 100 hours of the year (as is done by SDG&E in their approach to MCC allocation). LOLE modeling is a reasonable analytical tool that accounts for marginal capacity cost needs that exist outside of just the top 100 load hours. It is analytically superior to the simpler top 100 hours approach to MCC allocation.

Seasonal variations in marginal energy costs are minimal. The choice of using a 4-month summer season or a 6-month summer season is not clearly indicated when

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[10] See, for example, CAISO's findings in the TOU OIR docket, SDG&E's recommendations in this docket, CAISO findings in the 2014 LTPP process, and PG&E's findings in their most recent Rate Design Window docket (A.14-11-014).

[11] We note that the marginal cost reductions seen in the spring daytime hours in our PLEXOS modeling could be more severe if we constrained the PLEXOS model to prevent net exports from the CAISO region. We briefly discuss this later in the testimony.

considering only marginal energy costs; however, capacity cost concerns would indicate a shorter summer period.

II. Synapse Analysis of Marginal Generation Costs ("MGC")

Methodology and Modeling Conducted

Please summarize the methodology and modeling you use to estimate marginal generation costs.

We use two mathematical tools to conduct our analysis.

First, we employ PLEXOS modeling to produce hourly estimates of wholesale energy prices in the SDG&E region, for 2016 and 2020 (SDG&E used an estimate of marginal costs only for 2016 in their testimony). We offer 2016 and 2020 as "bookend" energy prices for consideration of SDG&E's MEC. Hourly energy prices represent marginal costs of procurement for wholesale spot market energy. We use a total MEC equal to the wholesale energy price and the RPS adder, as computed by SDG&E.

Next, to estimate hourly MCC, we use the combination of i) an estimate for the fixed costs for a new peaking resource, and ii) the allocation of those costs over high use hours based on the results of use of an LOLE model. We use the hourly LOLE model introduced in SCE's rate case[12], adapting it for our own use for the SDG&E service territory by using different load and resource inputs. We also use the LOLE model to estimate MCC allocations assuming a CAISO total system, rather than a SDG&E system. This topological change shrinks the number of hours in which LOLE is seen, as it captures resource and load diversity across the IOUs as it may impact reliability. To the extent this effect is considered or used in MCC allocations, it tends to concentrate marginal capacity costs into fewer hours of the year. We use the SDG&E system results for MCC allocation because they better represent the actual topology of the SDG&E system, whereas defining just a single CAISO system without any internal transmission interfaces may oversimplify the analysis.

[12] SCE submitted its LOLE model as part of the Workpapers in its 2015 GRC Phase 2, A.14-06-014.

The hourly LOLE model results in an estimate of the relative differences across hours of resource adequacy "tightness" for the SDG&E region. It is not an estimator for absolute loss-of-load; its strength lies in its relative simplicity, effectively performing an energy balance for all hours of the year, accounting for all loads and resources and transmission system import capacity (at a zonal level), and doing this repeatedly to reflect the stochastic nature of its load and resource (and to a lesser degree, transmission[13]) inputs. It produces an alternative to the 100 top load hours SDG&E uses to allocate the costs of a marginal unit of capacity resource. This method instead allocates MCC, proportionately, to any hour in which LOLE is greater than zero. We executed this model using load and resource inputs for 2016, and for 2020, based on the same underlying load and resource inputs we used in the PLEXOS model.

Based on the results of our marginal energy and marginal capacity cost estimation, we create hourly marginal generation costs for 2016 and 2020. Using our recommended definitions for TOU periods, we average the hourly values of marginal generation cost to determine an overall marginal generation cost for each of the defined seasonal and on-peak/off-peak periods.

Development of Marginal Energy, Capacity, and Generation Costs

How did you estimate marginal energy costs ("MEC")?

We used PLEXOS production cost simulation modeling to produce spot hourly energy prices for all hours of the year, for 2016 and 2020. Using production cost simulation modeling is superior to SDG&E's use of a forward pricing curve and historical load patterns because it more finely estimates the hourly dispatch effect on pricing in the SDG&E region. The forward pricing curves used by SDG&E contain aggregate on-peak and off-peak pricing estimates without any hourly distinction, a key consideration when looking to estimate hourly-based TOU periods. The hourly

[13] Transmission inputs for the LOLE model include a forced outage representation, thus import capacity associated with a zonal transmission path is, in some iterations, effectively forced out of service in the model, based on chance and the underlying stochastic parameter for transmission outages.

production cost simulation modeling also more carefully captures the hourly effects of the presence of solar photovoltaics ("PV") on the California system.

How did you develop the inputs for the PLEXOS model runs?

Starting with the Trajectory case developed for 2024 in the 2014 LTPP docket, we modified loads and resources throughout California and the WECC to develop a 2016 and a 2020 case. We used the CEC California Energy Demand 2015 Revised (2016-2026) load forecast for all California areas. We used the US EIA's 2015 Annual Energy Outlook to update load forecast information for the rest of the WECC areas. We incorporated Mid-AAEE levels of increased energy efficiency by modifying the baseline CED forecast. We used the load profiles that were embedded in the 2014 LTPP for each of the California IOU regions. We "backed out" all behind-the-meter solar generation from the CED forecast and represented this resource as a supply resource in PLEXOS, consistent with how CAISO treats such self-generation. We allowed net exports from the CAISO region, and we did not impose a 25% minimum regional generation requirement. We used currently planned retirement schedules for once-through-cooling ("OTC") resources, and we included planned Track 1 and Track 4 resource additions[14] in our 2020 modeling. Further documentation of our model input development is provided in Appendix A.

Please explain in further detail key assumptions used in the PLEXOS modeling construct.

We modified two PLEXOS constraints that were imposed by CAISO during its modeling in the 2014 LTPP. For 2016 and 2020, we relaxed the "no net exports" constraint and allowed net exports to flow from the CAISO region in those intervals when it was economic to do so. The presence of the CAISO Energy Imbalance Market ("EIM") is the primary reason for relaxing this constraint, as the EIM enhances the ability for economic transfers between the CAISO and the participating EIM regions.[15] The EIM

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[14] Pursuant to Decisions in the 2012 LTPP Track 1 and Track 4, D.13-02-015, D.14-03-004.

[15] Historically, CAISO is a net importer of power from adjacent regions. At times, however, CAISO

has been in place since 2014 (when PacifiCorp first joined); Nevada Energy joined in December of 2015. Arizona Public Service and Puget Sound Power and Light will join in October of 2016, followed by Portland General Electric in October of 2017, and Idaho Power in 2018.[16] 2016 LTPP Planning Assumptions support a relaxation of the "no net exports" assumption.[17]

We removed the constraint that forced the dispatch and unit commitment to ensure 25% generation from local resources within each of the major California zonal areas in PLEXOS – SCE, PG&E Valley, PG&E Bay, and SDG&E. This constraint, if imposed, has the effect of increasing curtailment of renewable resources in some hours by requiring a minimum amount of dispatchable (i.e., fossil or hydro) local resources to be online and producing. CAISO has indicated that it is eliminating this constraint for future LTPP modeling exercises, and replacing it with a frequency response requirement that better reflects the reliability and operational constraints to which CAISO must respond.[18]

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exports energy to adjacent regions. Economic transfers out of California – net exports - occur when supply and demand conditions, such as low load and high renewable generation in California, produce lower prices in California relative to marginal energy costs (or prices) in adjacent regions.

[16] Dates listed are based on information in the EIM participation agreements, and may be subject to change. Participation agreements are available on the CAISO website: https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

[17] The 2016 LTPP Planning assumptions support at least some relaxation of this constraint: "In regards to exports, the LTPP planning assumptions have historically been silent on the potential quantity of exports. The CAISO has, in the past, imposed a modeling constraint of "no net exports." This reflects historical practice, but as the system moves forward with regionalization efforts, further work is required to establish appropriate assumptions on the potential exports in different planning futures. In the 2016 LTPP, we expressly include an assumption that California "may" export energy." R.13-12-010. Administrative Law Judge's Ruling Seeking Comment on Assumptions and Scenarios for use in the CAISO 2016-2017 Transmission Planning Process and Future Commission Proceedings. Att. 1, pg 44. February 8th, 2016

[18] R.13-12-010. Administrative Law Judge's Ruling Seeking Comment on Assumptions and Scenarios for use in the CAISO 2016-2017 Transmission Planning Process and Future Commission Proceedings. Att. 1, pg 44. February 8th, 2016.

How did you estimate marginal capacity costs ("MCC")?

We estimated hourly marginal capacity costs by allocating the costs of a marginal unit of capacity to those hours with a relative LOLE or LOLP[19] greater than zero, in proportion to the LOLE/LOLP value. This resulted in a weighted assignment of marginal capacity unit costs to a different set of hours than the top 100 hours used by SDG&E to assign marginal capacity unit costs. We did this for ORA's estimated value of marginal capacity of $91.83/kW-year.[20] This method is superior to SD&E's use of just the "top 100" hours of load because it more formally analyzes (and includes in marginal capacity cost allocation) all of those hourly periods of time when the system is relatively stressed and may require additional capacity – those periods are not limited to solely to the top 100 hours of peak load. There are other periods of time when loads are not at their peak level but resource availability is constrained.

Did you include any marginal capacity cost allocation in hours that do not have an expectation of loss of load from the LOLE model, but may exhibit potential limitations on available flexible capacity?

No. At this time, we do not have an estimate of the need for marginal capacity in those hours with potential effective flexible capacity ("EFC") shortages.[21] If we had such an estimate, those hours could be included in the total hours across the year to which marginal capacity costs are allocated.

How did you estimate marginal generation costs (MGC)?

We estimated hourly marginal generation costs by summing the results of the marginal energy and marginal capacity costs across all hours of the year, for both 2016 and 2020.

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[19] We use LOLE and LOLP interchangeably in this testimony. Loss of load event and loss of load expectation are two different parameters, but our LOLE modeling results in a relative loss of load probability, or expectation. We do not use the loss of load event characterization in any way in this testimony.

[20] See ORA Testimony of Benjamin Gutierrez, Chapter 2.

[21] Effective flexible capacity is one of the required Resource Adequacy obligations that SDG&E, and other utilities, will bear. While EFC is needed in all hours, a marginal need for EFC is only indicated if existing resources are not able to provide the requirements in all hours.

How did you develop the inputs for the LOLE model?

We used the loads and resources from our PLEXOS modeling inputs for 2016 and 2020 as our starting point for the LOLE model assumptions. This model is fundamentally different from the PLEXOS model, but it does require a stochastic representation of loads, and a stochastic pattern for forced outages for resources. It also uses a stochastic distribution to represent solar and wind output profiles for any given day within each month.

How did you address curtailment issues and the marginal costs, or prices, for curtailment?

The CAISO model allows wind and solar resources to be curtailed in hours of excess generation. To provide a signal that this is occurring, it sets a price in those hours of -$300/MWh. While the current real-time market bid floor is -$150/MWh, and declines to -$300/MWh in the future, there is no expectation that all curtailment hours will hit this floor. We used a value of -$300/MWh in all curtailment hours.[22]

Results of Modeling

Please present the marginal generation cost ("MGC") modeling results.

The following tables, or "heat maps", show our results for 2016 and 2020 modeling of MGC, MEC, and MCC, by month and by hour of the day. Table 4-4 shows results for 2016 MGC, for "all hours" and differentiated between weekday and weekend hours. Tables 4-5 and 4-6 show similar time period information for MEC and MCC. Tables 4-7 (MGC), 4-8 (MEC) and 4- 9 (MCC) show the same information for 2020. Table 4-10 compares our 2020 MGC results to SDG&E's 2021 MGC results filed in the R.15-12-012 case.[23]

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[22] The CES21 workshop (CPUC Workshop Presentation, "Flexibility Metrics and Standards Project – a California Energy Systems for the 21st Century (CES-21)" January 6, 2016, slide 21) assumed a curtailment cost of $50/MWh. We used $30/MWh curtailment cost based on Pacific Gas& Electric's Rate Design Window filing (A.14-11-014.

[23] R.15-12-012 Supplemental Information Filing of San Diego Gas & Electric (U 902 E), April 29, 2016.

Table 4-4 2016 MGC Heat Maps, SDG&E Region Configuration – MGC, by Period

SDGE 2016 Total Marginal Generation Cost ($/MWh): Weekday

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	41.1	40.6	39.9	39.2	40.0	43.7	47.3	51.8	47.3	42.4	42.3	41.4	40.7	40.5	40.3	42.3	50.4	68.6	63.1	57.1	52.8	47.9	46.5	40.9
FEB	39.3	39.2	38.9	38.6	39.8	44.8	46.5	52.4	44.8	43.4	41.2	40.7	39.5	39.5	40.2	41.7	47.0	54.6	55.0	55.0	53.2	46.3	46.0	39.7
MAR	38.7	38.2	38.3	38.3	38.2	40.0	43.4	47.0	43.5	39.1	37.1	36.3	35.1	35.5	35.6	36.6	39.6	43.8	51.6	54.4	52.3	49.3	44.7	41.6
APR	38.2	36.9	36.9	37.0	37.1	37.6	41.9	44.5	38.9	34.8	33.0	31.8	31.1	31.0	31.6	33.0	36.6	38.8	47.7	47.1	53.3	52.7	47.7	42.2
MAY	38.6	37.7	36.9	36.9	36.6	38.4	41.6	39.7	38.4	36.3	36.1	36.3	36.1	36.5	37.8	39.7	42.2	46.9	51.3	51.0	51.5	53.4	49.8	46.4
JUN	39.4	40.0	38.9	38.3	37.9	38.9	41.1	39.0	37.9	37.2	37.4	37.7	37.6	37.5	38.4	40.1	44.3	50.5	52.0	51.3	52.6	60.4	49.9	44.2
JUL	46.1	44.9	43.0	42.1	42.0	42.3	44.3	42.7	42.9	46.2	59.0	76.8	100.8	114.7	160.8	221.4	314.6	419.8	346.0	194.6	161.6	189.8	80.2	53.6
AUG	45.5	44.0	42.9	41.9	41.7	42.1	44.6	46.1	43.6	41.3	44.1	52.1	67.9	83.4	105.0	130.6	174.9	224.4	209.6	123.8	184.1	134.6	61.7	50.1
SEP	42.7	43.0	40.9	40.2	39.7	39.9	44.2	46.7	42.5	39.9	39.9	40.4	41.7	43.5	49.4	61.0	85.0	111.8	110.7	128.0	149.5	87.2	50.3	46.5
OCT	42.3	42.9	41.1	40.3	40.0	39.5	45.0	47.2	45.9	39.9	39.7	39.8	40.0	40.6	42.7	49.4	61.2	78.1	64.5	99.3	75.2	55.4	49.6	48.2
NOV	41.9	41.6	40.7	40.1	41.0	45.6	47.4	48.9	43.1	39.0	38.8	39.3	38.8	39.0	40.0	44.2	78.9	155.3	119.6	73.1	59.6	48.9	48.7	43.2
DEC	43.9	41.4	40.6	40.7	41.0	47.1	49.4	53.2	45.6	41.8	40.4	39.8	39.3	39.2	39.9	44.6	65.3	131.5	104.1	73.2	56.3	52.6	53.4	44.0

SDGE 2016 Total Marginal Generation Cost ($/MWh): Weekend or Holiday

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	43.4	41.2	40.7	41.2	42.1	45.0	45.2	47.6	42.3	38.5	38.3	38.0	38.1	37.8	37.8	39.1	47.4	57.0	56.3	52.2	50.9	47.5	46.3	41.1
FEB	40.7	39.1	40.0	39.6	40.4	44.1	43.3	44.5	40.6	38.0	37.8	36.2	36.0	35.5	36.6	36.8	43.1	56.7	64.6	51.0	48.8	45.8	42.3	38.9
MAR	39.2	39.2	39.2	38.7	38.6	38.8	39.8	40.1	38.1	35.4	32.9	31.2	30.2	30.8	31.3	32.4	33.8	48.6	67.1	106.1	65.5	48.7	42.9	39.6
APR	38.7	38.2	38.0	38.1	39.6	40.3	40.7	39.6	35.7	28.4	26.5	25.9	25.9	25.3	26.0	27.3	29.8	37.4	46.9	50.3	88.0	56.9	45.2	42.5
MAY	40.0	39.2	38.3	39.1	40.1	40.6	40.7	35.5	33.3	29.2	29.3	29.3	29.0	30.1	32.1	33.7	37.2	41.2	49.5	49.0	49.6	50.7	47.8	44.1
JUN	38.3	37.4	37.6	37.0	37.8	38.3	37.7	34.7	33.1	31.5	31.3	31.9	31.5	32.3	32.9	34.8	36.6	39.6	47.0	55.4	128.4	192.5	63.5	42.7
JUL	44.5	44.3	43.0	41.9	41.7	41.2	42.1	40.7	38.6	37.8	38.4	40.0	41.5	43.0	44.6	54.1	57.8	71.1	83.6	75.3	79.4	110.8	55.8	47.2
AUG	46.7	44.7	42.7	42.2	41.9	41.6	43.1	43.6	38.6	38.2	38.0	38.9	45.6	59.5	80.3	98.6	113.9	141.7	164.3	123.4	151.5	115.1	73.8	49.1
SEP	41.4	41.8	40.6	40.3	39.8	39.8	43.0	42.7	38.6	36.9	35.7	36.2	35.7	36.4	37.2	38.2	40.0	44.6	48.7	60.7	109.0	59.6	48.1	43.3
OCT	41.0	42.2	40.8	40.6	40.3	40.9	42.7	44.7	41.2	37.2	35.8	36.3	35.8	35.6	36.5	38.3	40.4	46.5	47.6	67.1	54.9	48.4	46.0	42.4
NOV	42.2	43.0	41.4	40.5	43.1	44.0	43.9	44.3	38.1	36.7	36.7	36.2	36.1	36.0	36.6	38.2	49.9	97.0	90.1	60.9	51.5	48.3	46.2	41.3
DEC	45.578	43.248	41.361	42.322	42.274	43.597	46.701	48.583	42.327	38.444	37.518	37.540	36.900	37.373	37.326	39.825	49.644	59.887	58.034	55.243	55.204	50.007	47.986	42.009

SDGE 2016 Total Marginal Generation Cost ($/MWh): All Hours

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	41.9	40.8	40.2	39.9	40.7	44.2	46.6	50.3	45.5	41.0	40.9	40.2	39.8	39.5	39.4	41.2	49.3	64.5	60.7	55.3	52.1	47.7	46.4	41.0
FEB	39.7	39.2	39.3	38.9	40.0	44.6	45.5	49.9	43.5	41.7	40.2	39.3	38.4	38.3	39.1	40.2	45.8	55.2	58.0	53.8	51.9	46.1	44.9	39.4
MAR	38.8	38.4	38.5	38.4	38.3	39.7	42.5	45.2	42.1	38.1	36.0	35.0	33.9	34.3	34.5	35.5	38.1	45.1	55.6	67.7	55.7	49.1	44.2	41.1
APR	38.4	37.3	37.2	37.3	37.8	38.4	41.5	43.0	38.0	32.9	31.1	30.1	29.5	29.3	29.9	31.3	34.5	38.4	47.5	48.1	63.7	54.0	46.9	42.3
MAY	39.0	38.2	37.3	37.6	37.6	39.0	41.3	38.5	36.9	34.2	34.1	34.2	34.1	34.6	36.1	37.9	40.8	45.2	50.8	50.4	51.0	52.6	49.2	45.7
JUN	39.1	39.3	38.5	37.9	37.8	38.8	40.2	37.9	36.7	35.7	35.8	36.2	35.9	36.1	36.9	38.7	42.3	47.6	50.6	52.4	72.8	95.6	53.5	43.8
JUL	45.6	44.7	43.0	42.0	41.9	42.0	43.6	42.0	41.5	43.5	52.3	64.9	81.7	91.6	123.3	167.4	231.8	307.3	261.4	156.1	135.1	164.3	72.4	51.5
AUG	45.8	44.2	42.8	42.0	41.8	42.0	44.2	45.5	42.3	40.5	42.5	48.7	62.2	77.2	98.6	122.3	159.1	203.1	197.9	123.7	175.7	129.6	64.8	49.9
SEP	42.3	42.7	40.8	40.2	39.8	39.9	43.9	45.6	41.4	39.1	38.8	39.3	40.1	41.6	46.1	54.9	73.0	93.9	94.2	110.1	138.7	79.8	49.7	45.6
OCT	41.9	42.7	41.0	40.4	40.1	39.9	44.3	46.4	44.4	39.1	38.4	38.7	38.7	39.0	40.7	45.8	54.5	67.9	59.1	88.9	68.6	53.1	48.5	46.3
NOV	42.0	42.0	40.9	40.2	41.6	45.2	46.5	47.7	41.7	38.4	38.2	38.5	38.1	38.2	39.1	42.6	71.1	139.8	111.7	69.8	57.4	48.7	48.0	42.7
DEC	44.4	41.9	40.8	41.2	41.3	46.1	48.6	51.9	44.6	40.9	39.6	39.1	38.6	38.7	39.1	43.2	60.8	110.7	90.7	68.0	56.0	51.9	51.8	43.4

Notes: ORA Capacity Cost, All Hours LOLE Allocation, With RPS Adder

Table 4-5 2016 MEC Heat Maps, SDG&E Region Configuration – MEC, by Period

SDGE 2016 Total Marginal Energy Cost ($/MWh): Weekday

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	41.1	40.6	39.9	39.2	40.0	43.7	47.3	51.8	47.3	42.4	42.3	41.4	40.7	40.5	40.3	42.3	50.4	55.0	56.2	55.8	52.8	47.9	46.5	40.9
FEB	39.3	39.2	38.9	38.6	39.8	44.8	46.5	52.4	44.8	43.4	41.2	40.7	39.5	39.5	40.2	41.7	47.0	54.3	54.8	55.0	53.2	46.3	46.0	39.7
MAR	38.7	38.2	38.3	38.3	38.2	40.0	43.4	47.0	43.5	39.1	37.1	36.3	35.1	35.5	35.6	36.6	39.6	43.8	51.2	52.7	52.3	49.3	44.7	41.6
APR	38.2	36.9	36.9	37.0	37.1	37.6	41.9	44.5	38.9	34.8	33.0	31.8	31.1	31.0	31.6	33.0	36.6	38.8	47.7	46.2	49.4	51.8	47.7	42.2
MAY	38.6	37.7	36.9	36.9	36.6	38.4	41.6	39.7	38.4	36.3	36.1	36.3	36.1	36.5	37.8	39.7	42.2	46.9	51.3	51.0	51.5	53.4	49.8	46.4
JUN	39.4	40.0	38.9	38.3	37.9	38.9	41.1	39.0	37.9	37.2	37.4	37.7	37.4	37.4	38.2	39.6	43.2	49.0	51.0	51.3	50.8	51.6	49.9	44.2
JUL	46.1	44.9	43.0	42.1	42.0	42.3	44.3	42.7	42.3	41.9	42.9	43.9	44.8	45.8	47.5	50.4	52.8	54.0	55.5	56.3	54.4	54.3	52.6	52.2
AUG	45.5	44.0	42.9	41.9	41.7	42.1	44.6	46.1	43.6	41.2	41.5	42.4	43.8	45.9	48.4	50.0	52.5	53.8	55.9	54.5	53.9	53.8	51.5	50.1
SEP	42.7	43.0	40.9	40.2	39.7	39.9	44.2	46.7	42.5	39.9	39.9	39.9	40.1	40.5	42.3	43.6	46.9	50.5	52.7	51.8	52.6	51.8	49.8	46.5
OCT	42.3	42.9	41.1	40.3	40.0	39.5	45.0	47.2	45.9	39.9	39.7	39.8	39.9	40.1	40.8	43.1	46.7	52.8	52.4	54.4	54.8	54.7	49.6	48.2
NOV	41.9	41.6	40.7	40.1	41.0	45.6	47.4	48.9	43.1	39.0	38.7	39.3	38.7	39.0	40.0	44.2	51.6	54.9	55.3	53.2	52.8	48.4	48.7	43.2
DEC	43.9	41.4	40.6	40.7	41.0	47.1	49.4	53.2	45.6	41.8	40.4	39.8	39.3	39.2	39.9	44.6	53.9	58.8	57.8	56.3	56.2	52.6	53.4	44.0

SDGE 2016 Total Marginal Energy Cost ($/MWh): Weekend or Holiday

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	43.4	41.2	40.7	41.2	42.1	45.0	45.2	47.6	42.3	38.5	38.3	38.0	38.1	37.8	37.8	39.1	47.4	53.7	54.5	52.0	50.9	47.5	46.3	41.1
FEB	40.7	39.1	40.0	39.6	40.4	44.1	43.3	44.5	40.6	38.0	37.8	36.2	36.0	35.5	36.6	36.8	43.1	48.9	51.3	49.8	48.8	45.8	42.3	38.9
MAR	39.2	39.2	39.2	38.7	38.6	38.8	39.8	40.1	38.1	35.4	32.9	31.2	30.2	30.8	31.3	32.4	33.8	40.3	46.3	48.2	49.3	47.6	42.9	39.6
APR	38.7	38.2	38.0	38.1	39.6	40.3	40.7	39.6	35.7	28.4	26.5	25.9	25.9	25.3	26.0	27.3	29.8	37.4	46.9	44.6	48.2	51.1	45.2	42.5
MAY	40.0	39.2	38.3	39.1	40.1	40.6	40.7	35.5	33.3	29.2	29.3	29.3	29.0	30.1	32.1	33.7	37.2	41.2	49.5	49.0	48.9	50.7	47.8	44.1
JUN	38.3	37.4	37.6	37.0	37.8	38.3	37.7	34.7	33.1	31.5	31.3	31.6	31.3	32.3	32.8	34.7	36.4	39.2	44.0	47.0	45.1	48.5	48.4	42.4
JUL	44.5	44.3	43.0	41.9	41.7	41.2	42.1	40.7	38.6	37.8	38.4	39.8	41.0	42.3	43.0	48.9	46.3	49.9	53.1	55.2	52.9	53.0	52.3	47.2
AUG	46.7	44.7	42.7	42.2	41.9	41.6	43.1	43.6	38.6	38.2	37.9	38.5	40.0	42.8	44.8	46.6	48.6	52.7	54.7	54.4	54.0	53.5	52.4	49.1
SEP	41.4	41.8	40.6	40.3	39.8	39.8	43.0	42.7	38.6	36.9	35.7	36.2	35.7	36.4	37.2	38.2	40.0	44.6	48.7	49.0	51.2	49.7	48.1	43.3
OCT	41.0	42.2	40.8	40.6	40.3	40.9	42.7	44.7	41.2	37.2	35.8	36.3	35.8	35.6	36.5	38.3	40.4	46.4	47.4	48.8	50.1	48.4	46.0	42.4
NOV	42.2	43.0	41.4	40.5	43.1	44.0	43.9	44.3	38.1	36.7	36.7	36.2	36.1	36.0	36.6	38.2	49.0	54.2	56.3	53.3	51.5	48.3	46.2	41.3
DEC	45.6	43.2	41.4	42.3	42.3	43.6	46.7	48.6	42.3	38.4	37.5	37.5	36.9	37.4	37.3	39.8	49.6	54.7	55.9	55.2	55.2	50.0	48.0	42.0

SDGE 2016 Total Marginal Energy Cost ($/MWh): All Hours

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	41.9	40.8	40.2	39.9	40.7	44.2	46.6	50.3	45.5	41.0	40.9	40.2	39.8	39.5	39.4	41.2	49.3	54.5	55.6	54.4	52.1	47.7	46.4	41.0
FEB	39.7	39.2	39.3	38.9	40.0	44.6	45.5	49.9	43.5	41.7	40.2	39.3	38.4	38.3	39.1	40.2	45.8	52.6	53.7	53.4	51.9	46.1	44.9	39.4
MAR	38.8	38.4	38.5	38.4	38.3	39.7	42.5	45.2	42.1	38.1	36.0	35.0	33.9	34.3	34.5	35.5	38.1	42.9	49.9	51.5	51.5	48.9	44.2	41.1
APR	38.4	37.3	37.2	37.3	37.8	38.4	41.5	43.0	38.0	32.9	31.1	30.1	29.5	29.3	29.9	31.3	34.5	38.4	47.5	45.7	49.1	51.6	46.9	42.3
MAY	39.0	38.2	37.3	37.6	37.6	39.0	41.3	38.5	36.9	34.2	34.1	34.2	34.1	34.6	36.1	37.9	40.8	45.2	50.8	50.4	50.8	52.6	49.2	45.7
JUN	39.1	39.3	38.5	37.9	37.8	38.8	40.2	37.9	36.7	35.7	35.7	36.0	35.8	36.0	36.8	38.3	41.4	46.4	49.1	50.1	49.3	50.8	49.5	43.7
JUL	45.6	44.7	43.0	42.0	41.9	42.0	43.6	42.0	41.1	40.5	41.5	42.6	43.6	44.7	46.0	49.9	50.7	52.7	54.7	55.9	54.0	53.9	52.5	50.6
AUG	45.8	44.2	42.8	42.0	41.8	42.0	44.2	45.5	42.3	40.4	40.6	41.4	42.8	45.1	47.5	49.1	51.5	53.5	55.6	54.4	53.9	53.8	51.8	49.9
SEP	42.3	42.7	40.8	40.2	39.8	39.9	43.9	45.6	41.4	39.1	38.8	39.0	38.9	39.4	40.9	42.2	45.1	48.9	51.6	51.1	52.2	51.2	49.3	45.6
OCT	41.9	42.7	41.0	40.4	40.1	39.9	44.3	46.4	44.4	39.1	38.4	38.7	38.6	38.7	39.4	41.6	44.7	50.7	50.8	52.6	53.3	52.7	48.5	46.3
NOV	42.0	42.0	40.9	40.2	41.6	45.2	46.5	47.7	41.7	38.4	38.2	38.4	38.0	38.2	39.1	42.6	50.9	54.7	55.5	53.2	52.5	48.4	48.0	42.7
DEC	44.4	41.9	40.8	41.2	41.3	46.1	48.6	51.9	44.6	40.9	39.6	39.1	38.6	38.7	39.1	43.2	52.7	57.6	57.3	56.0	55.9	51.9	51.8	43.4

Notes: ORA Capacity Cost, All Hours LOLE Allocation, With RPS Adder

Table 4-6 2016 MCC Heat Maps, SDG&E Region Configuration – MCC, by Period

SDGE 2016 Total Marginal Capacity Cost ($/MWh): Weekday

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.7	6.9	1.3	0.0	0.0	0.0	0.0
FEB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.0	0.0	0.0	0.0	0.0
MAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	1.7	0.0	0.0	0.0	0.0
APR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	3.8	0.9	0.0	0.0
MAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JUN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.5	1.2	1.6	1.0	0.0	1.9	8.8	0.0	0.0
JUL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	4.4	16.0	32.9	56.0	68.9	113.3	171.0	261.8	365.8	290.6	138.3	107.1	135.4	27.6	1.4
AUG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	9.6	24.2	37.5	56.6	80.6	122.4	170.6	153.7	69.3	130.2	80.8	10.1	0.0
SEP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.6	3.0	7.1	17.4	38.0	61.4	58.0	76.2	97.0	35.4	0.5	0.0
OCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	1.9	6.2	14.5	25.3	12.1	45.0	20.4	0.6	0.0	0.0
NOV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	27.3	100.5	64.3	19.9	6.8	0.5	0.0	0.0
DEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	72.6	46.3	16.9	0.2	0.0	0.0	0.0

SDGE 2016 Total Marginal Capacity Cost ($/MWh): Weekend or Holiday

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	1.9	0.2	0.0	0.0	0.0	0.0
FEB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.8	13.3	1.1	0.0	0.0	0.0	0.0
MAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	20.8	57.9	16.1	1.1	0.0	0.0
APR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7	39.7	5.8	0.0	0.0
MAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0
JUN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.0	0.0	0.1	0.1	0.4	2.9	8.4	83.3	144.0	15.2	0.2
JUL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.6	0.7	1.6	5.2	11.5	21.2	30.5	20.1	26.5	57.8	3.5	0.0
AUG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	5.6	16.7	35.5	51.9	65.3	89.0	109.7	69.0	97.5	61.5	21.4	0.0
SEP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7	57.8	9.9	0.0	0.0
OCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	18.3	4.8	0.0	0.0	0.0
NOV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	42.7	33.8	7.6	0.0	0.0	0.0	0.0
DEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	2.1	0.1	0.0	0.0	0.0	0.0

SDGE 2016 Total Marginal Capacity Cost ($/MWh): All Hours

	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	5.1	0.9	0.0	0.0	0.0	0.0
FEB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	4.3	0.4	0.0	0.0	0.0	0.0
MAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	5.7	16.2	4.2	0.3	0.0	0.0
APR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	14.6	2.4	0.0	0.0
MAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0
JUN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.4	0.9	1.3	1.5	2.3	23.6	44.9	4.0	0.1
JUL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	3.0	10.9	22.3	38.1	46.9	77.3	117.5	181.1	254.6	206.7	100.2	81.1	110.4	19.8	1.0
AUG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	7.2	19.4	32.1	51.2	73.2	107.7	149.6	142.3	69.2	121.8	75.8	13.0	0.0
SEP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.2	2.2	5.2	12.7	27.9	45.0	42.6	59.0	86.5	28.6	0.4	0.0
OCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	1.3	4.2	9.8	17.2	8.3	36.4	15.4	0.4	0.0	0.0
NOV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	20.2	85.1	56.2	16.6	5.0	0.4	0.0	0.0
DEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	53.0	33.4	12.0	0.1	0.0	0.0	0.0

Notes: ORA Capacity Cost, All Hours LOLE Allocation, With RPS Adder

Table 4-7 2020 MGC Heat Maps, SDG&E Region Configuration – MGC, by Period

SDGE 2020 Total Marginal Generation Cost ($/MWh): Weekday

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	49.9	48.2	47.7	47.7	48.9	54.7	56.1	62.0	55.8	47.7	47.3	46.4	46.1	45.7	46.5	46.6	59.1	87.1	75.2	63.6	59.9	54.2	55.7	49.4
FEB	47.6	46.6	46.7	46.6	47.2	54.7	54.6	61.6	51.0	47.6	45.9	44.7	44.8	44.6	45.0	45.0	52.6	66.0	70.9	62.3	59.1	53.4	55.5	48.2
MAR	44.1	42.5	42.9	42.6	43.2	44.6	48.1	50.7	47.2	41.0	37.4	35.3	34.3	34.4	35.5	36.7	41.2	46.9	58.0	61.4	61.7	57.4	54.5	50.8
APR	46.6	41.8	41.6	41.3	41.8	42.7	46.8	48.6	42.3	36.1	33.5	31.9	31.5	31.1	32.1	33.8	37.7	43.7	56.6	55.6	70.0	66.8	58.2	55.9
MAY	44.7	41.1	40.2	41.4	41.0	41.5	44.9	41.8	38.4	37.4	37.0	37.0	36.9	37.2	38.5	40.2	45.1	51.9	65.4	58.8	58.1	61.2	58.4	55.4
JUN	47.1	44.8	44.4	44.0	44.2	44.7	46.3	43.2	41.9	40.9	40.7	40.7	40.3	40.5	42.2	44.8	49.0	54.8	61.0	61.1	60.1	63.6	57.5	52.7
JUL	53.3	53.0	51.8	51.5	51.1	51.1	52.3	51.7	51.0	51.3	55.2	59.6	64.4	69.0	82.4	108.2	150.9	210.2	237.9	193.8	186.2	200.8	95.3	61.9
AUG	51.4	51.8	50.7	50.9	50.2	51.0	52.3	53.2	51.0	50.5	59.7	67.0	78.4	91.9	112.0	137.2	182.8	253.2	294.7	231.1	304.3	270.5	132.7	60.3
SEP	50.0	50.2	49.3	49.0	48.6	49.0	51.4	53.6	50.3	45.8	45.7	45.7	45.7	46.0	48.4	54.1	71.1	102.8	112.3	140.1	151.4	92.0	55.5	53.9
OCT	49.7	50.8	49.6	49.4	48.8	49.4	53.0	54.2	54.5	45.7	45.2	45.4	45.8	46.6	49.5	56.4	74.4	111.3	136.3	208.5	140.5	75.9	54.2	54.8
NOV	49.8	49.7	48.9	48.3	49.8	58.1	57.3	60.9	47.2	43.8	42.7	42.7	42.5	42.9	43.0	48.3	67.4	85.6	74.1	67.2	60.4	54.9	58.1	50.7
DEC	46.8	45.8	45.3	45.2	45.6	51.3	54.9	55.8	48.7	43.9	42.7	41.7	41.8	41.6	41.4	45.5	58.3	111.0	93.6	70.7	57.9	54.0	54.9	48.0

SDGE 2020 Total Marginal Generation Cost ($/MWh): Weekend or Holiday

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	48.9	47.2	47.0	48.2	48.4	49.8	51.7	55.4	47.7	42.6	41.3	41.4	40.6	40.3	39.8	42.0	51.8	80.4	69.1	61.5	57.6	54.8	54.6	49.3
FEB	46.9	47.1	47.3	46.9	47.5	50.1	50.2	50.0	42.9	40.4	39.6	37.1	37.3	36.8	39.9	40.2	47.9	118.8	136.2	92.1	56.3	54.8	53.1	47.4
MAR	45.8	44.1	44.3	43.9	44.1	44.3	45.0	44.3	40.8	35.1	30.6	23.5	22.6	26.5	27.5	29.8	32.8	43.7	60.2	99.0	75.9	55.9	50.4	47.3
APR	47.8	43.4	41.8	41.7	43.2	43.4	44.0	43.3	34.7	26.3	24.9	22.7	22.7	23.4	24.0	26.3	29.6	39.4	50.6	50.9	125.7	83.8	54.7	49.7
MAY	47.2	44.1	42.4	41.8	42.2	42.7	41.5	36.8	32.5	28.7	27.6	28.6	28.9	28.9	29.6	32.3	37.0	44.4	57.2	60.7	79.6	79.3	59.0	52.2
JUN	46.7	43.4	42.1	42.5	43.0	43.1	43.0	39.3	33.4	30.6	30.6	30.3	30.6	30.3	33.2	37.7	40.5	47.7	57.4	61.2	76.6	120.5	60.1	50.7
JUL	52.5	53.3	51.1	50.7	50.6	49.9	50.9	47.4	45.7	44.1	43.8	46.3	46.7	48.4	51.5	53.3	59.0	77.1	98.5	97.8	98.8	122.9	64.8	55.5
AUG	53.6	53.7	52.1	52.1	51.4	51.4	52.0	52.3	45.7	44.0	43.7	45.6	51.5	63.3	83.5	96.7	108.0	135.0	195.2	149.1	252.7	213.9	108.4	61.4
SEP	50.6	49.9	48.7	48.3	47.6	48.3	49.4	49.9	44.1	39.0	36.9	36.0	36.8	37.7	39.4	41.7	45.0	52.7	55.5	64.9	87.0	59.7	54.3	52.7
OCT	50.7	50.5	49.0	48.7	48.9	50.2	53.1	52.6	47.2	39.2	36.7	36.2	34.9	34.8	35.6	38.5	42.3	58.1	67.5	191.0	134.4	59.0	54.5	54.7
NOV	50.8	49.9	50.0	50.1	49.5	54.9	55.1	53.1	45.5	40.5	39.4	37.7	37.2	38.1	40.7	43.4	62.9	69.3	66.4	63.7	58.5	56.2	55.6	50.6
DEC	52.4	51.2	48.4	48.6	49.0	51.5	53.5	54.2	46.6	43.5	41.8	40.7	40.3	39.5	40.4	42.6	58.0	68.4	63.8	61.8	59.3	56.7	55.9	50.9

SDGE 2020 Total Marginal Generation Cost ($/MWh): All Hours

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	49.6	48.0	47.6	47.8	48.8	53.4	55.0	60.3	53.7	46.4	45.8	45.1	44.7	44.3	44.8	45.4	57.2	85.3	73.6	63.1	59.3	54.3	55.4	49.4
FEB	47.3	46.7	46.9	46.7	47.3	53.3	53.3	58.0	48.5	45.4	43.9	42.4	42.5	42.2	43.4	43.5	51.1	82.4	91.1	71.5	58.2	53.8	54.8	47.9
MAR	44.6	42.9	43.3	43.0	43.5	44.5	47.2	48.8	45.3	39.3	35.5	31.9	30.9	32.1	33.2	34.7	38.7	46.0	58.6	72.3	65.8	57.0	53.3	49.8
APR	46.9	42.2	41.6	41.4	42.2	42.9	46.1	47.2	40.3	33.5	31.2	29.4	29.1	29.0	29.9	31.8	35.5	42.6	55.0	54.3	84.8	71.3	57.3	54.2
MAY	45.5	42.1	40.9	41.5	41.4	41.9	43.8	40.2	36.5	34.6	34.0	34.3	34.3	34.5	35.6	37.6	42.5	49.5	62.8	59.4	65.0	67.0	58.6	54.4
JUN	47.0	44.4	43.8	43.6	43.9	44.3	45.4	42.2	39.6	38.1	38.0	38.0	37.7	37.8	39.8	42.9	46.7	52.9	60.0	61.1	64.5	78.8	58.2	52.1
JUL	53.1	53.1	51.6	51.3	51.0	50.8	52.0	50.6	49.6	49.5	52.3	56.2	59.8	63.7	74.4	94.0	127.2	175.8	201.9	169.0	163.6	180.7	87.4	60.2
AUG	52.1	52.4	51.1	51.3	50.6	51.1	52.2	52.9	49.3	48.4	54.6	60.1	69.7	82.7	102.8	124.1	158.7	215.1	262.6	204.7	287.7	252.2	124.9	60.7
SEP	50.2	50.2	49.1	48.8	48.4	48.8	50.8	52.6	48.6	44.0	43.3	43.1	43.3	43.8	46.0	50.8	64.1	89.4	97.2	120.0	134.2	83.4	55.2	53.6
OCT	50.0	50.7	49.5	49.2	48.9	49.6	53.0	53.7	52.3	43.8	42.7	42.7	42.6	43.1	45.5	51.2	65.1	95.8	116.3	203.4	138.7	71.0	54.3	54.7
NOV	50.2	49.8	49.3	49.0	49.7	56.9	56.5	58.0	46.6	42.6	41.5	40.8	40.6	41.1	42.1	46.5	65.7	79.6	71.3	65.9	59.7	55.4	57.2	50.7
DEC	48.4	47.4	46.2	46.2	46.6	51.4	54.5	55.3	48.1	43.8	42.4	41.4	41.4	41.0	41.1	44.6	58.2	98.7	85.0	68.1	58.3	54.8	55.2	48.8

Notes: ORA Capacity Cost, All Hours LOLE Allocation, With RPS Adder

Table 4-8 2020 MEC Heat Maps, SDG&E Region Configuration – MEC, by Period

SDGE 2020 Total Marginal Energy Cost ($/MWh): Weekday

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	49.9	48.2	47.7	47.7	48.9	54.7	56.1	62.0	55.8	47.7	47.3	46.4	46.1	45.7	46.5	46.6	58.3	63.9	65.0	62.3	59.9	54.2	55.7	49.4
FEB	47.6	46.6	46.7	46.6	47.2	54.7	54.6	61.6	51.0	47.6	45.9	44.7	44.8	44.6	45.0	45.0	52.6	59.7	64.2	61.9	59.1	53.4	55.5	48.2
MAR	44.1	42.5	42.9	42.6	43.2	44.6	48.1	50.7	47.2	41.0	37.4	35.3	34.3	34.4	35.5	36.7	41.2	46.9	57.8	60.0	61.3	57.4	54.5	50.8
APR	46.6	41.8	41.6	41.3	41.8	42.7	46.8	48.6	42.3	36.1	33.5	31.9	31.5	31.1	32.1	33.8	37.7	43.7	56.6	55.6	58.0	63.3	58.2	55.9
MAY	44.7	41.1	40.2	41.4	41.0	41.5	44.9	41.8	38.4	37.4	37.0	37.0	36.9	37.2	38.5	40.2	45.1	51.9	65.4	58.8	58.1	61.2	58.4	55.4
JUN	47.1	44.8	44.4	44.0	44.2	44.7	46.3	43.2	41.9	40.9	40.7	40.7	40.3	40.5	42.2	44.7	48.8	53.9	57.6	59.9	57.8	57.4	56.5	52.7
JUL	53.3	53.0	51.8	51.5	51.1	51.1	52.3	51.7	50.7	49.7	50.2	50.7	50.9	52.5	54.3	56.6	59.8	62.3	65.3	65.5	62.8	62.7	59.7	59.8
AUG	51.4	51.8	50.7	50.9	50.2	51.0	52.3	53.2	50.9	48.6	48.8	48.5	48.5	49.7	53.0	54.1	57.6	60.9	64.3	62.6	60.4	61.0	57.7	57.2
SEP	50.0	50.2	49.3	49.0	48.6	49.0	51.4	53.6	50.3	45.8	45.7	45.7	45.6	45.8	47.0	49.0	52.3	57.1	58.8	58.1	59.6	58.4	55.3	53.9
OCT	49.7	50.8	49.6	49.4	48.8	49.4	53.0	54.2	54.5	45.7	45.2	45.3	45.2	45.0	45.8	47.0	51.3	60.8	59.7	61.1	61.6	59.6	54.2	54.8
NOV	49.8	49.7	48.9	48.3	49.8	58.1	57.3	60.9	47.2	43.8	42.7	42.7	42.5	42.9	43.0	48.3	65.5	68.8	67.3	65.3	60.4	54.9	58.1	50.7
DEC	46.8	45.8	45.3	45.2	45.6	51.3	54.9	55.8	48.7	43.9	42.7	41.7	41.8	41.6	41.4	45.5	56.1	61.1	61.2	59.7	57.7	54.0	54.9	48.0

SDGE 2020 Total Marginal Energy Cost ($/MWh): Weekend or Holiday

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	48.9	47.2	47.0	48.2	48.4	49.8	51.7	55.4	47.7	42.6	41.3	41.4	40.6	40.3	39.8	42.0	51.8	62.0	60.8	61.3	57.6	54.8	54.6	49.3
FEB	46.9	47.1	47.3	46.9	47.5	50.1	50.2	50.0	42.9	40.4	39.6	37.1	37.3	36.8	39.9	40.2	47.9	58.5	60.0	57.9	55.9	54.8	53.1	47.4
MAR	45.8	44.1	44.3	43.9	44.1	44.3	45.0	44.3	40.8	35.1	30.6	23.5	22.6	26.5	27.5	29.8	32.8	42.1	52.3	57.6	57.5	54.5	50.4	47.3
APR	47.8	43.4	41.8	41.7	43.2	43.4	44.0	43.3	34.7	26.3	24.9	22.7	22.7	23.4	24.0	26.3	29.6	39.4	50.6	50.9	54.1	58.6	54.6	49.7
MAY	47.2	44.1	42.4	41.8	42.2	42.7	41.5	36.8	32.5	28.7	27.6	28.6	28.9	28.9	29.6	32.3	37.0	44.4	56.9	59.5	57.2	60.1	57.9	52.2
JUN	46.7	43.4	42.1	42.5	43.0	43.1	43.0	39.3	33.4	30.6	30.6	30.3	30.6	30.3	33.2	37.7	40.3	47.3	55.0	58.1	55.4	56.2	55.5	50.7
JUL	52.5	53.3	51.1	50.7	50.6	49.9	50.9	47.4	45.7	44.1	43.8	46.3	46.6	48.2	51.0	51.9	53.5	58.4	61.9	66.1	60.3	61.4	58.4	55.5
AUG	53.6	53.7	52.1	52.1	51.4	51.4	52.0	52.3	45.7	44.0	43.4	43.9	45.0	47.3	49.3	51.8	54.8	61.0	63.2	62.0	61.7	62.3	59.5	55.7
SEP	50.6	49.9	48.7	48.3	47.6	48.3	49.4	49.9	44.1	39.0	36.9	36.0	36.8	37.7	39.4	41.7	45.0	52.7	55.5	55.2	57.3	56.9	54.3	52.7
OCT	50.7	50.5	49.0	48.7	48.9	50.2	53.1	52.6	47.2	39.2	36.7	36.2	34.9	34.8	35.6	38.5	42.3	58.1	58.4	58.1	59.0	56.4	54.5	54.7
NOV	50.8	49.9	50.0	50.1	49.5	54.9	55.1	53.1	45.5	40.5	39.4	37.7	37.2	38.1	40.7	43.4	62.9	67.3	66.4	63.7	58.5	56.2	55.6	50.6
DEC	52.4	51.2	48.4	48.6	49.0	51.5	53.5	54.2	46.6	43.5	41.8	40.7	40.3	39.5	40.4	42.6	58.0	63.9	62.1	61.6	59.3	56.7	55.9	50.9

SDGE 2020 Total Marginal Energy Cost ($/MWh): All Hours

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	49.6	48.0	47.6	47.8	48.8	53.4	55.0	60.3	53.7	46.4	45.8	45.1	44.7	44.3	44.8	45.4	56.6	63.4	63.9	62.0	59.3	54.3	55.4	49.4
FEB	47.3	46.7	46.9	46.7	47.3	53.3	53.3	58.0	48.5	45.4	43.9	42.4	42.5	42.2	43.4	43.5	51.1	59.3	62.9	60.6	58.1	53.8	54.8	47.9
MAR	44.6	42.9	43.3	43.0	43.5	44.5	47.2	48.8	45.3	39.3	35.5	31.9	30.9	32.1	33.2	34.7	38.7	45.5	56.2	59.3	60.2	56.6	53.3	49.8
APR	46.9	42.2	41.6	41.4	42.2	42.9	46.1	47.2	40.3	33.5	31.2	29.4	29.1	29.0	29.9	31.8	35.5	42.6	55.0	54.3	56.9	62.1	57.3	54.2
MAY	45.5	42.1	40.9	41.5	41.4	41.9	43.8	40.2	36.5	34.6	34.0	34.3	34.3	34.5	35.6	37.6	42.5	49.5	62.7	59.0	57.8	60.8	58.2	54.4
JUN	47.0	44.4	43.8	43.6	43.9	44.3	45.4	42.2	39.6	38.1	38.0	38.0	37.7	37.8	39.8	42.8	46.6	52.1	56.9	59.4	57.2	57.1	56.3	52.1
JUL	53.1	53.1	51.6	51.3	51.0	50.8	52.0	50.6	49.4	48.3	48.5	49.6	49.8	51.3	53.5	55.4	58.2	61.3	64.4	65.6	62.2	62.4	59.4	58.7
AUG	52.1	52.4	51.1	51.3	50.6	51.1	52.2	52.9	49.2	47.1	47.0	47.0	47.4	48.9	51.8	53.4	56.7	60.9	63.9	62.4	60.8	61.5	58.3	56.7
SEP	50.2	50.2	49.1	48.8	48.4	48.8	50.8	52.6	48.6	44.0	43.3	43.1	43.3	43.7	44.9	47.1	50.3	55.9	57.9	57.3	59.0	58.0	55.0	53.6
OCT	50.0	50.7	49.5	49.2	48.9	49.6	53.0	53.7	52.3	43.8	42.7	42.6	42.2	42.1	42.8	44.5	48.7	60.0	59.3	60.2	60.9	58.7	54.3	54.7
NOV	50.2	49.8	49.3	49.0	49.7	56.9	56.5	58.0	46.6	42.6	41.5	40.8	40.6	41.1	42.1	46.5	64.5	68.2	66.9	64.7	59.7	55.4	57.2	50.7
DEC	48.4	47.4	46.2	46.2	46.6	51.4	54.5	55.3	48.1	43.8	42.4	41.4	41.4	41.0	41.1	44.6	56.7	61.9	61.4	60.3	58.2	54.8	55.2	48.8

Notes: ORA Capacity Cost, All Hours LOLE Allocation, With RPS Adder

Table 4-9 2020 MCC Heat Maps, SDG&E Region Configuration – MCC, by Period

SDGE 2020 Total Marginal Capacity Cost ($/MWh): Weekday

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	23.2	10.3	1.3	0.0	0.0	0.0	0.0
FEB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.3	6.6	0.4	0.0	0.0	0.0	0.0
MAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.4	0.4	0.0	0.0	0.0
APR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	3.4	0.0	0.0
MAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JUN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.9	3.3	1.2	2.3	6.2	0.9	0.0
JUL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	5.0	9.0	13.5	16.6	28.1	51.6	91.0	147.9	172.6	128.4	123.3	138.1	35.6	2.1
AUG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.9	11.0	18.6	30.0	42.2	59.0	83.1	125.2	192.3	230.4	168.5	243.9	209.5	75.0	3.1
SEP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.4	5.1	18.9	45.7	53.5	82.0	91.7	33.6	0.3	0.0
OCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.6	1.5	3.7	9.4	23.1	50.5	76.6	147.4	78.9	16.3	0.0	0.0
NOV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	16.8	6.9	1.9	0.0	0.0	0.0	0.0
DEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	49.9	32.5	11.0	0.2	0.0	0.0	0.0

SDGE 2020 Total Marginal Capacity Cost ($/MWh): Weekend or Holiday

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.4	8.3	0.2	0.0	0.0	0.0	0.0
FEB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.3	76.2	34.2	0.4	0.0	0.0	0.0
MAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	7.9	41.4	18.3	1.3	0.0	0.0
APR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.6	25.1	0.1	0.0
MAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.2	22.4	19.2	1.2	0.0
JUN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	2.4	3.1	21.1	64.3	4.6	0.0
JUL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5	1.4	5.5	18.6	36.6	31.8	38.6	61.5	6.3	0.0
AUG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.7	6.4	16.0	34.2	44.9	53.2	74.0	132.0	87.1	191.0	151.5	48.9	5.8
SEP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	9.7	29.7	2.8	0.0	0.0
OCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.1	132.9	75.4	2.6	0.0	0.0
NOV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0
DEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	1.7	0.2	0.0	0.0	0.0	0.0

SDGE 2020 Total Marginal Capacity Cost ($/MWh): All Hours

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	22.0	9.7	1.0	0.0	0.0	0.0	0.0
FEB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.0	28.2	10.9	0.1	0.0	0.0	0.0
MAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	2.4	13.0	5.6	0.4	0.0	0.0
APR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.9	9.2	0.0	0.0
MAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	7.2	6.2	0.4	0.0
JUN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.8	3.1	1.7	7.3	21.7	1.9	0.0
JUL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.2	3.7	6.7	10.0	12.3	21.0	38.6	69.0	114.6	137.5	103.4	101.5	118.4	28.0	1.5
AUG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.3	7.5	13.1	22.4	33.8	51.0	70.8	102.0	154.1	198.7	142.2	226.8	190.8	66.6	4.0
SEP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.0	3.8	13.8	33.5	39.3	62.7	75.2	25.4	0.2	0.0
OCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	1.1	2.6	6.7	16.4	35.8	57.0	143.2	77.9	12.3	0.0	0.0
NOV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	11.4	4.3	1.2	0.0	0.0	0.0	0.0
DEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	36.7	23.5	7.9	0.1	0.0	0.0	0.0

Notes: ORA Capacity Cost, All Hours LOLE Allocation, With RPS Adder

Table 4-10 Comparison of Synapse 2020 MGC results to SDG&E 2012 OIR TOU Results

Synapse Results, 2020 MGC, Weekday and Weekend Hours

SDGE 2020 Total Marginal Generation Cost ($/MWh): Weekday

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	38.4	36.8	36.3	36.2	37.5	43.2	44.7	50.5	44.4	36.2	35.9	35.0	34.7	34.2	35.1	35.2	46.8	52.4	53.5	50.8	48.5	42.8	44.3	37.9
FEB	36.1	35.2	35.2	35.2	35.8	43.3	43.2	50.2	39.5	36.2	34.4	33.3	33.4	33.2	33.6	33.5	41.2	48.3	52.8	50.5	47.7	42.0	44.1	36.7
MAR	32.6	31.0	31.5	31.2	31.8	33.2	36.7	39.2	35.8	29.6	26.0	23.9	22.9	23.0	24.1	25.2	29.7	35.5	46.4	48.6	49.8	46.0	43.1	39.4
APR	35.1	30.4	30.1	29.9	30.4	31.3	35.4	37.2	30.8	24.6	22.0	20.4	20.0	19.6	20.7	22.4	26.3	32.3	45.1	44.1	46.5	51.9	46.8	44.4
MAY	33.3	29.6	28.7	30.0	29.5	30.0	33.5	30.3	27.0	26.0	25.6	25.6	25.5	25.8	27.0	28.7	33.7	40.5	54.0	47.3	46.7	49.7	47.0	44.0
JUN	35.7	33.3	32.9	32.6	32.8	33.3	34.9	31.8	30.4	29.4	29.3	29.3	28.9	29.1	30.7	33.3	37.4	42.4	46.2	48.4	46.3	45.9	45.1	41.2
JUL	41.9	41.6	40.4	40.0	39.7	39.7	40.9	40.2	39.3	38.3	38.7	39.2	39.5	41.0	61.3	86.3	153.1	279.1	323.0	237.1	232.2	254.4	80.7	48.4
AUG	39.9	40.3	39.2	39.4	38.7	39.5	40.9	41.8	39.4	37.1	37.3	37.0	54.5	94.0	140.8	172.6	242.5	368.8	492.1	327.3	525.5	436.5	148.0	45.8
SEP	38.6	38.8	37.8	37.5	37.2	37.6	39.9	42.2	38.8	34.4	34.3	34.2	34.2	34.4	35.5	37.6	55.2	103.5	127.2	154.1	132.9	76.1	43.8	42.4
OCT	38.3	39.3	38.2	38.0	37.4	37.9	41.6	42.7	43.0	34.2	33.7	33.8	33.7	33.6	34.4	35.6	74.3	129.6	192.1	269.6	127.5	48.2	42.8	43.3
NOV	38.4	38.3	37.4	36.9	38.4	46.7	45.8	49.5	35.8	32.4	31.3	31.2	31.1	31.4	31.6	36.9	54.0	57.3	55.8	53.9	49.0	43.4	46.7	39.3
DEC	35.4	34.4	33.9	33.8	34.2	39.9	43.4	44.4	37.3	32.5	31.2	30.3	30.4	30.1	30.0	34.0	44.7	49.7	49.7	48.3	46.3	42.6	43.5	36.5

SDGE 2020 Total Marginal Generation Cost ($/MWh): Weekend or Holiday

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	37.4	35.8	35.6	36.8	36.9	38.3	40.3	44.0	36.3	31.2	29.8	29.9	29.2	28.8	28.3	30.5	40.4	50.6	49.4	49.8	46.2	43.4	43.1	37.9
FEB	35.4	35.6	35.9	35.4	36.0	38.7	38.7	38.5	31.5	29.0	28.2	25.7	25.8	25.3	28.5	28.8	36.5	47.1	48.6	46.4	44.5	43.4	41.7	36.0
MAR	34.3	32.6	32.8	32.5	32.7	32.8	33.5	32.9	29.3	23.7	19.2	12.0	11.2	15.1	16.1	18.4	21.4	30.7	40.8	46.1	46.1	43.1	39.0	35.9
APR	36.4	32.0	30.4	30.3	31.7	32.0	32.6	31.9	23.3	14.9	13.4	11.2	11.3	11.9	12.5	14.8	18.1	28.0	39.2	39.5	42.6	47.2	43.2	38.2
MAY	35.8	32.7	31.0	30.4	30.8	31.2	30.0	25.4	21.1	17.3	16.1	17.2	17.5	17.5	18.1	20.9	25.6	33.0	45.5	48.0	45.8	48.7	46.4	40.7
JUN	35.3	32.0	30.7	31.1	31.6	31.7	31.6	27.8	22.0	19.1	19.1	18.9	19.1	18.9	21.8	26.2	28.9	35.8	43.6	46.6	44.0	44.8	44.1	39.3
JUL	41.0	41.8	39.6	39.3	39.1	38.5	39.4	36.0	34.3	32.7	32.3	34.9	35.1	36.7	39.6	40.5	42.1	47.0	50.5	54.6	48.8	50.0	47.0	44.1
AUG	42.2	42.3	40.7	40.7	40.0	40.0	40.5	40.9	34.3	32.6	32.0	32.5	33.6	35.9	75.9	129.1	143.5	191.3	239.7	185.6	410.6	300.0	145.0	44.2
SEP	39.2	38.5	37.2	36.9	36.2	36.8	37.9	38.5	32.7	27.6	25.4	24.6	25.3	26.3	27.9	30.3	33.5	41.3	44.0	43.8	45.8	45.5	42.9	41.3
OCT	39.2	39.1	37.6	37.3	37.5	38.7	41.6	41.1	35.7	27.8	25.3	24.7	23.4	23.4	24.1	27.1	30.9	46.6	47.0	224.1	47.5	45.0	43.0	43.2
NOV	39.4	38.5	38.5	38.7	38.1	43.4	43.7	41.6	34.0	29.0	28.0	26.2	25.8	26.7	29.2	32.0	51.5	55.9	54.9	52.2	47.1	44.8	44.2	39.2
DEC	40.9	39.8	36.9	37.2	37.6	40.0	42.0	42.8	35.2	32.1	30.4	29.3	28.8	28.1	29.0	31.1	46.6	52.4	50.7	50.2	47.8	45.3	44.5	39.4

SDG&E Results, 2021 MGC, Weekday and Weekend Hours

2021 Total Marginal Generation Cost $/kWh (MGC): Weekday (Non-Holiday)

Month	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	0.037	0.035	0.034	0.034	0.035	0.038	0.038	0.040	0.041	0.040	0.038	0.035	0.035	0.035	0.040	0.042	0.045	0.052	0.056	0.053	0.048	0.043	0.044	0.039
FEB	0.037	0.035	0.035	0.035	0.036	0.039	0.040	0.043	0.042	0.039	0.034	0.029	0.027	0.030	0.035	0.041	0.045	0.055	0.058	0.055	0.050	0.045	0.044	0.040
MAR	0.038	0.035	0.033	0.033	0.033	0.035	0.039	0.042	0.041	0.035	0.027	0.021	0.020	0.022	0.030	0.041	0.049	0.053	0.055	0.055	0.056	0.053	0.047	0.042
APR	0.034	0.032	0.030	0.030	0.029	0.030	0.042	0.044	0.043	0.036	0.025	0.020	0.019	0.019	0.024	0.032	0.043	0.053	0.058	0.059	0.060	0.061	0.043	0.038
MAY	0.035	0.032	0.030	0.029	0.028	0.028	0.040	0.042	0.039	0.028	0.027	0.019	0.020	0.019	0.027	0.035	0.045	0.053	0.057	0.058	0.060	0.062	0.044	0.039
JUN	0.034	0.030	0.029	0.028	0.027	0.027	0.041	0.040	0.033	0.026	0.018	0.017	0.019	0.024	0.026	0.033	0.048	0.064	0.068	0.067	0.063	0.063	0.041	0.038
JUL	0.039	0.035	0.033	0.031	0.031	0.031	0.041	0.042	0.040	0.034	0.026	0.024	0.028	0.031	0.035	0.045	0.061	0.068	0.103	0.111	0.265	0.104	0.049	0.044
AUG	0.040	0.036	0.034	0.032	0.032	0.032	0.039	0.041	0.041	0.038	0.032	0.028	0.026	0.034	0.041	0.094	0.154	0.221	0.270	0.491	0.657	0.273	0.051	0.045
SEP	0.040	0.036	0.034	0.032	0.032	0.032	0.039	0.044	0.043	0.038	0.034	0.031	0.032	0.071	0.130	0.225	0.313	0.356	0.463	0.876	0.658	0.297	0.086	0.045
OCT	0.041	0.037	0.036	0.034	0.034	0.034	0.035	0.040	0.040	0.038	0.033	0.027	0.025	0.029	0.039	0.047	0.054	0.057	0.059	0.092	0.056	0.053	0.051	0.045
NOV	0.039	0.037	0.036	0.035	0.035	0.037	0.040	0.040	0.035	0.030	0.026	0.025	0.026	0.031	0.039	0.048	0.056	0.059	0.058	0.056	0.054	0.050	0.048	0.043
DEC	0.037	0.036	0.035	0.035	0.036	0.039	0.037	0.040	0.041	0.040	0.038	0.037	0.036	0.038	0.041	0.043	0.044	0.051	0.150	0.110	0.046	0.041	0.045	0.040

2021 Total Marginal Generation Cost $/kWh (MGC): Weekend or Holiday

Month	Hour Ending (Clock Time/Pacific Prevailing Time)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
JAN	0.033	0.031	0.030	0.030	0.030	0.032	0.031	0.032	0.033	0.032	0.030	0.028	0.024	0.027	0.031	0.034	0.038	0.043	0.045	0.044	0.042	0.040	0.039	0.036
FEB	0.036	0.034	0.033	0.033	0.033	0.034	0.034	0.035	0.034	0.032	0.027	0.021	0.021	0.021	0.027	0.033	0.038	0.044	0.046	0.045	0.044	0.042	0.041	0.038
MAR	0.037	0.035	0.033	0.031	0.031	0.031	0.032	0.033	0.033	0.031	0.028	0.025	0.018	0.015	0.021	0.030	0.037	0.042	0.045	0.046	0.047	0.047	0.044	0.041
APR	0.032	0.031	0.029	0.028	0.027	0.027	0.031	0.031	0.029	0.024	0.022	0.014	0.009	0.013	0.012	0.021	0.024	0.036	0.042	0.044	0.045	0.045	0.038	0.036
MAY	0.033	0.031	0.028	0.027	0.026	0.026	0.031	0.031	0.027	0.021	0.020	0.004	0.007	0.006	0.015	0.023	0.032	0.039	0.042	0.044	0.046	0.048	0.040	0.036
JUN	0.032	0.031	0.029	0.027	0.026	0.026	0.032	0.030	0.025	0.011	0.002	0.004	0.006	0.008	0.010	0.011	0.029	0.039	0.048	0.049	0.048	0.048	0.039	0.036
JUL	0.037	0.035	0.032	0.030	0.029	0.028	0.033	0.032	0.030	0.025	0.020	0.013	0.014	0.020	0.027	0.030	0.041	0.051	0.054	0.055	0.053	0.053	0.044	0.041
AUG	0.038	0.037	0.034	0.031	0.031	0.030	0.033	0.032	0.029	0.022	0.015	0.013	0.013	0.015	0.019	0.029	0.038	0.049	0.054	0.133	0.155	0.052	0.047	0.043
SEP	0.038	0.036	0.033	0.031	0.030	0.030	0.033	0.035	0.033	0.030	0.025	0.019	0.017	0.020	0.023	0.035	0.043	0.050	0.139	0.380	0.285	0.130	0.046	0.042
OCT	0.037	0.036	0.033	0.032	0.031	0.030	0.030	0.031	0.031	0.028	0.019	0.013	0.009	0.013	0.016	0.031	0.039	0.045	0.049	0.050	0.049	0.048	0.046	0.043
NOV	0.038	0.035	0.033	0.032	0.031	0.032	0.032	0.030	0.026	0.021	0.019	0.019	0.020	0.024	0.031	0.039	0.047	0.051	0.051	0.050	0.049	0.046	0.043	0.040
DEC	0.038	0.036	0.034	0.034	0.034	0.035	0.032	0.034	0.036	0.036	0.035	0.034	0.033	0.034	0.036	0.037	0.040	0.046	0.048	0.046	0.045	0.042	0.043	0.039

<u>Comparison – Synapse 2020 and SDG&E 2021 MGC Results</u>

Please compare the relevant 2020 results from your modeling with SDG&E's MGC estimates for 2021 based on SDG&E's OIR TOU docket filing.

Table 4-10 above contains weekday and weekend hours MGC values from SDG&E's estimates for 2021, and Synapse's estimates for 2020. SDG&E and Synapse have results that show similar patterns in the grouping of hourly MGC, even though the results also exhibit differences. 1) Synapse estimates of relatively higher later afternoon/early evening summer season weekday MGC values persist across more hours than SDG&E's estimates, though SDG&E has the highest hourly MGC spikes; and 2) SDG&E's estimates lower marginal costs during midday hours compared to Synapse, particularly so during spring months. Weekend hours (for both Synapse and SDG&E modeling) have a smaller range of relatively high MGC values, over fewer hours and fewer months, though both SDG&E and Synapse modeling show spikes in later evening (8-9, or 8-10 PM) weekend hours for either August (Synapse) or September (SDG&E).

What do these results suggest in terms of the TOU periods under consideration for the SDG&E GRC?

These results suggest that the later-afternoon/early evening peak periods continue to be reasonable for future years out to at least 2021. They also show how sensitive MGC costs can be to the form of MCC allocation that is considered in any given modeling approach. Both our results, and SDG&E's results indicate relatively spiky high-cost MGC hours that probably do not reflect precision in the estimated period of greatest system stress, but rather are reflective of a modeling approach that allocates marginal costs over a relatively few hours.

In general, the results support ORA's recommendation for non-holiday weekday peak hour TOU periods (4 PM to 9 PM).

III. Issues Discussion

<u>LOLE Modeling – Zonal Configuration</u>

Please explain the SDGE and CAISO zone configuration differences used in the LOLE model.

We executed LOLE model runs using two different zonal configurations for the purpose of effectively assessing resource adequacy by estimating the LOLP for each hour of the year, for 2016 and 2020. First, we used a SDG&E-only regional configuration, using load and resources just within the SDG&E region, with transmission interconnections supporting import capacity into the region across two major paths, one from the northwest and one from the east. The modeling results used in our TOU period recommendations are based on these results. We also ran the LOLE model using a single CAISO region, with all loads and resources in a single area, and import capacity into the CAISO region modeled as multiple paths.

Please discuss the differences in results between SDG&E and CAISO region configurations.

The modeling results used in our TOU period recommendations are based on the SDG&E configuration. Figures 4-1 and 4-2 below show the LOLE results for each configuration. The MCC "all hours" portion of the heat maps shown in Table 4-6 represents the same LOLE results as is seen below in Figure 4-1 (Table 4-6 contains MCC in $/MWh; Figures 4-1 and 4-2 contain the raw hourly relative LOLE values). Figure 4-2 illustrates that using a CAISO region configuration, supply and load diversity across the IOU service territories results in only a single month of relative resource "tightness," July. In the CAISO configuration, there are no constraints between northern and southern California.

Figure 4-1. LOLE – SDG&E configuration - 2016

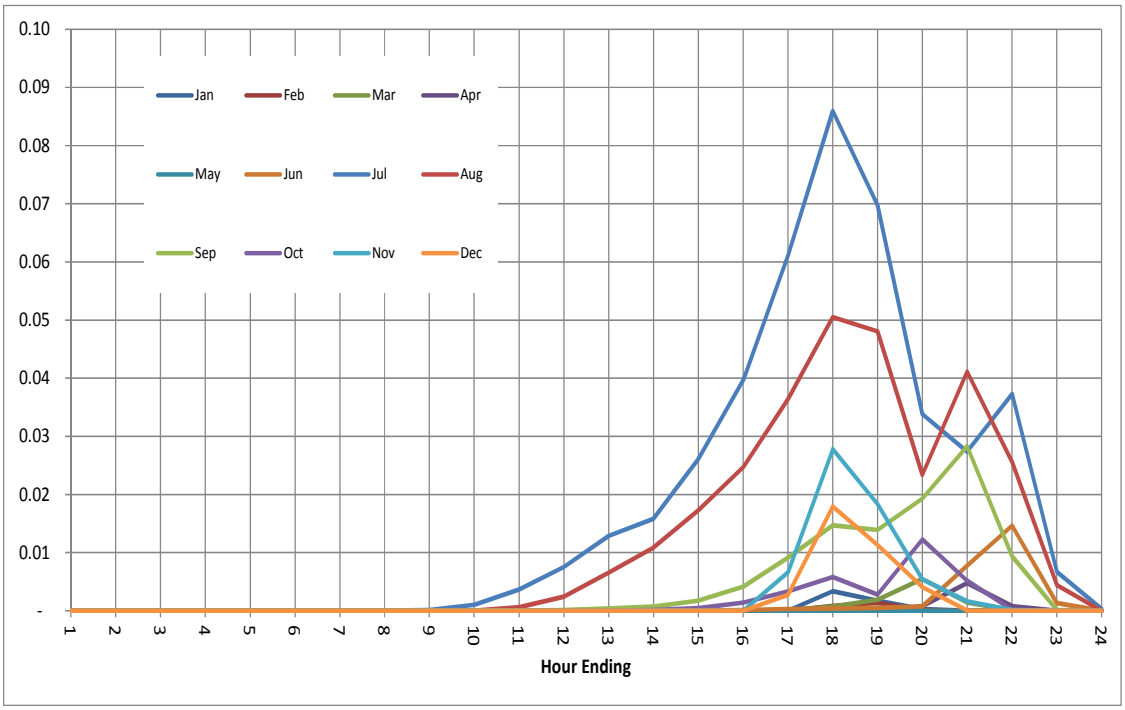
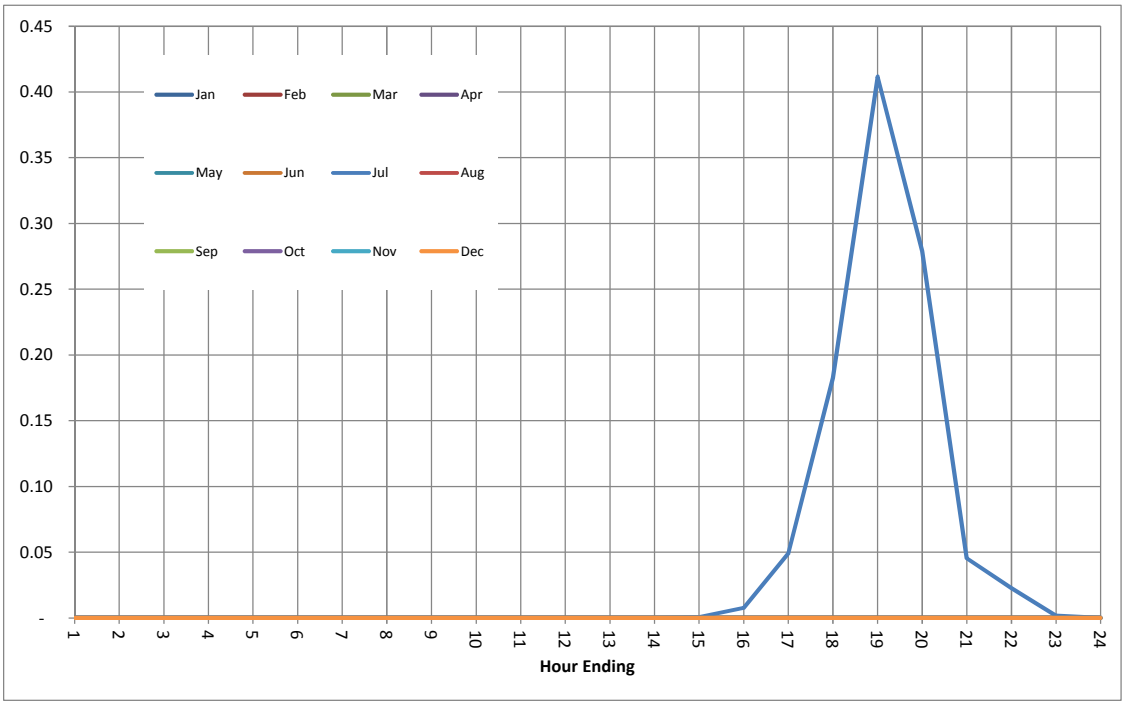


Figure 4-2. LOLE – CAISO configuration – 2016



Net Load

How does your modeling of marginal generation costs account for net load patterns?

The modeling results fully account for the net load patterns resulting from increased use of solar and wind resources. This reflects the detailed input assumptions that include the presence of all solar PV, both larger utility-scale and smaller behind-the-meter scale resources, and all wind resources. Solar PV and wind resources are fundamentally the drivers of the difference between "gross load" and net load patterns, essentially by definition of the term "net load." While we do not use "adjusted net load" (as put forth by CAISO, PG&E, and SDG&E) in any manner in our analysis, our modeling construct nonetheless fully reflects the presence of nuclear and hydro resources, whose output is used when defining "adjusted net load" patterns. Marginal energy costs that are a direct result of the PLEXOS modeling fully reflect, for example, the net load patterns that CAISO used in their OIR TOU filing[24], in which CAISO suggested TOU period definition based on those net load patterns. Net load patterns generally correlate to marginal energy cost patterns, but the patterns are not identical.

MEC and MCC Components

How do your modeling results weigh the contribution of marginal energy costs and marginal capacity costs when computing marginal generation costs?

The marginal generation cost metrics we compute and report in the MGC heat maps are a direct addition of the MEC and MCC components, which are normalized to $/MWh values. The MCC component is highly dependent on both the estimated marginal capacity cost (estimated by ORA as $91.83/kW-year, and by SDG&E as $118.16/kW-year) and the allocation of that cost using some form of LOLE or "top hours" methodology. The MCC allocation is not an exact science, and we urge restraint in how one interprets the highest MGC value that appears on a given MGC heat map. The more aggregate MGC value across seasons and peak/on peak periods (as reported in

[24] CAISO, Time-of-use Periods Analysis, January 22, 2016. Filed in R.15-12-012.

Tables 4-1 and 4-2) does not exhibit the "false precision" of a single high MGC value as is seen in the MGC heat map tables.

<u>Seasonal Definitions</u>

Please discuss the effect your modeling results have on consideration of the length of the summer and winter season (for example, six months vs. four months long) and whether to start the summer season – for SDG&E – in May, June, or July.

Marginal energy costs patterns are relatively stable across the months, as seen in Figure 4-3 below (and reflected in the heat maps shown in Tables 4-5 and 4-8). For TOU period purposes, the seasonality is not as important as the hourly patterns seen. When marginal capacity costs are added in, then the seasonal differences become stark, since more of those marginal costs are being assigned to summer period (especially July and August) than other months, as is also seen in the MCC heat maps of Tables 4-6 and 4-9.

Figure 4-3. Marginal Energy Cost Patterns, All Hours Average by Month, 2016

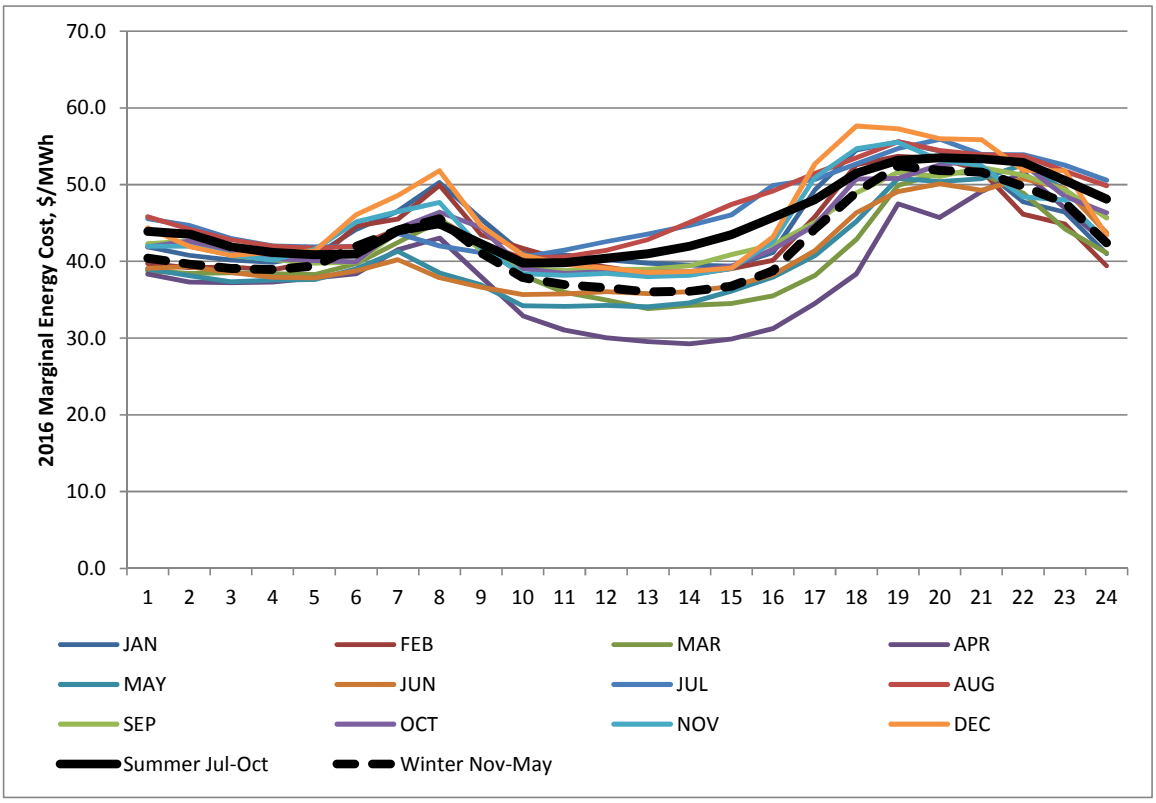
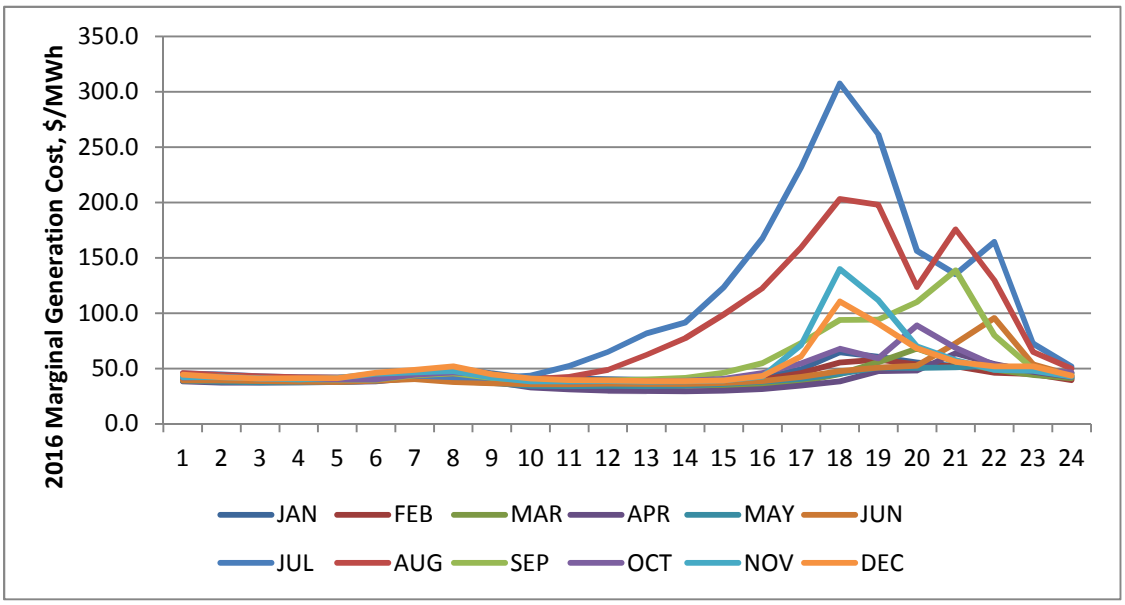


Figure 4-4. Marginal Generation Cost Patterns, All Hours Average by Month, 2016



Weekday vs. Weekend

Please comment on consideration of splitting the on-peak periods between weekdays and weekends.

The heat maps reveal that there is not much of a difference in the patterns of marginal energy costs, and a small difference in the patterns of marginal capacity costs, between weekend and weekday peak hours (4 PM to 9 PM). The value of the marginal costs is different (e.g., weekday prices during peak hours are larger than weekend prices during peak hours), but the patterns – higher marginal cost in the later hours, on both weekend and weekday, relative to costs earlier in the day – persist. Since weekday prices are higher than weekend prices for most months, ORA's suggested weekday-only peak period is reasonable.

Tables 4-4 through 4-9 show weekday and weekend MGC, MEC, and MCC for 2016 and 2020.

<u>2016 vs. 2020</u>

Please comment on how your 2016 results in comparison to your 2020 results affects consideration of TOU periods.

Since 2016 already exhibits the presence of a significant amount of solar PV resource, there is not a significant difference seen in the marginal cost patterns between 2016 and 2020. Absolute values are different, and there are some differences in specific heat map results, but the overall broad patterns support the TOU periods suggested.

Does this conclude your testimony?

Yes.

IV. APPENDIX A: Model Documentation

Please describe in detail how you determined 2020 baseline load profiles for production cost modeling.

We started with the CPUC-approved assumptions for the Trajectory scenario of the 2014 LTPP docket. As explained in the Attachment to the Planning Assumptions ACR:

> "The Trajectory scenario is the control scenario for resource and infrastructure planning, designed to reflect a modestly conservative future world with little change from existing procurement policies and little change from business as usual practices."[25]

We make adjustments to the 2024 model provided by CAISO to reflect our best understanding of loads and resources in 2016 and 2020, based on assumptions in the LTPP Scenario Tool, as well as other sources. The model provided in the LTPP docket was configured for 2024 only – the adjustments we made included:

- Annual Peak Loads and Annual Energy in CAISO, the rest of California, and the rest of WECC
- Revisions to thermal resource additions and retirements, resulting from recent CAISO dockets
- Installed PV capacity
- Storage resources
- Demand response resource
- RPS resources

[25] Attachment to Planning Assumptions ACR, p. 34. Other scenarios, and the order in which the Planning Assumptions ACR indicates they should be studies are: the High Load Scenario ,which explores the impact of higher than expected economic and demographic growth, the High DG [distributed generation] scenario, which explores the implications of promoting high amounts of DG; the 40% [Renewable Portfolio Standard]RPS in 2024 Scenario, which would assess the operational impacts associated with a higher RPS target post-2020, and the Expanded Preferred Resources scenario, which would assess the impact of broadly pursuing higher levels of preferred resources. Attachment to the Planning Assumptions ACR, pp. 37-38.

Thermal resources were set to retire and be added based on more current information than the LTPP dataset. A number of modifications have been made to the retirement forecasts required for compliance with the State Water Resources Control Board's once-through cooling (OTC) policy. The updated retirement dates in Table A-1 are based on a CEC progress report issued on August 24th, 2014.[26] More recent progress report information indicates that some of the retirements will be made slightly later than is indicated in Table A-1. This has no impact on our modeling for 2016. Generally the effect would be that our 2020 resource base slightly undercounts available capacity for the latter half of 2020; however, these units operate as peaking resources with relatively low capacity factors (Feb. 9, 2016 Progress Report, pages 3-4) and thus the overall impact on modeled MEC would be relatively small.

Thermal additions were made based on a number of data sources, and summarized in Table A-2. Large new combined-cycle units will be added in mid-2020 at or near the existing Huntington Beach and Alamitos sites, for a total of 1,284MW of capacity. New combustion turbines will be added at Mandalay, Carlsbad, Stanton, and Pio Pico totaling 1,062MW.[27,28]

A number of units slated to be retired in the next several years had to be added back in to the CAISO LTPP model for 2016. These include Encina, Moss Landing, Pittsburg, and the Long Beach Peakers. We also modeled the replacement of Broadway 3 with Glenarm5 in June of 2016.

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[26] California Energy Commission. "Once-Through Cooling Phase-Out". February 9th, 2016. http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf
Note: our analysis was based on the August 24th, 2014 edition of this report, no longer available online. Those assumptions are reflected in Table A-1.

[27] A.14-1-012. Testimony of SCE on the Results of Its 2013 LCR RFO for LA Basin. Table VII-25.

A.14-11-016. Testimony of SCE on the Results of Its 2013 LCR RFO for Moorpark. Table VII-22

[28] Note that Pio Pico was included in the 2014 LTPP analysis. We include it here for completeness.

Table A-1: Thermal Resource Adjustments from LTPP2014 Data set

Facility & Unit	NQC (MW)	Retirement Date
Alamitos 1	175	6/1/2020
Alamitos 2	175	6/1/2020
Alamitos 3	332	12/31/2020
Alamitos 4	336	12/31/2020
Alamitos 5	498	6/1/2019
Alamitos 6	495	12/31/2019
Huntington Beach 1	226	12/31/2018
Huntington Beach 2	226	12/31/2018
Mandalay 1	215	6/1/2020
Mandalay 2	215	6/1/2020
Mandaly3	130	12/31/2020
Ormond Beach 1	741	12/31/2020
Ormond Beach 2	775	12/31/2020
Redondo5	179	12/31/2020
Redondo6	175	12/31/2018
Redondo7	493	12/31/2020
Redondo8	496	12/31/2018

Table A-2: Thermal Resource additions to LTPP2014 Data set

Facility & Unit	NQC (MW)	Install Date
Huntington Beach CC	644	5/1/2020
Alamitos CC	640	6/1/2020
Mandalay Repower CT	262	6/1/2020
Carlsbad CT	500	1/1/2018
Stanton CT	98	7/1/2020
Pio Pico CT	300	12/31/2019

Loads in CAISO as well as the rest of California were adjusted based on the 2015 IEPR forecast (Form 1.5). No adjustments were made to the hourly pattern. Loads in all hours were scaled down based on the ratio of the 2015 IEPR energy forecast for 2020 to the 2013 IEPR energy forecast for 2024, the latter of which was used in the LTPP proceeding. We used the IEPR mid-demand, mid AAEE forecasts. Figure A-1 shows how these IEPR forecasts have changed over the last several years. Non-California regions (including the rest of the WECC) were adjusted downwards based on EIA's 2015 Annual Energy Outlook forecasts for WECC, which are about 4% lower in 2020 than 2024.

Behind-the-meter PV resources were adjusted based on IEPR Form 1.4-Mid. These values were presented as "Peak Demand Impact" values. We adjusted them to nameplate capacity based on the latest IEPR PV Peak Factors: 37% for PG&E and 40% for SCE and SDG&E. We adjusted for T&D losses based on values from the LTPP 2014 Scenario tool. The levels of behind-the-meter PV in the latest IEPR report are substantially greater than those in the LTPP 2014 scenario tool. The revised values are presented in Table A-4.

Table A-3: Recent IEPR Energy Forecasts (in GWh). IEPR 2013 was used in the LTPP model, while IEPR2015 was used in this analysis

	IEPR2014 Mid-MidAAEE			IEPR2013 Mid-MidAAEE
	2016	**2020**	**2024**	**2024**
SCE	108,814	105,417	106,509	108,888
IID	3,872	4,423	4,670	4,777
LDWP	28,068	29,508	31,002	32,618
PGE_BAY	42,097	46,708	46,895	47,377
PGE_VLY	61,549	62,242	63,311	63,065
SDGE	21,068	21,491	21,452	21,846
SMUD	16,950	18,916	19,917	20,117
TIDC	2,690	2,941	3,069	2,978

Figure A-1: Change in recent years IEPR forecasts

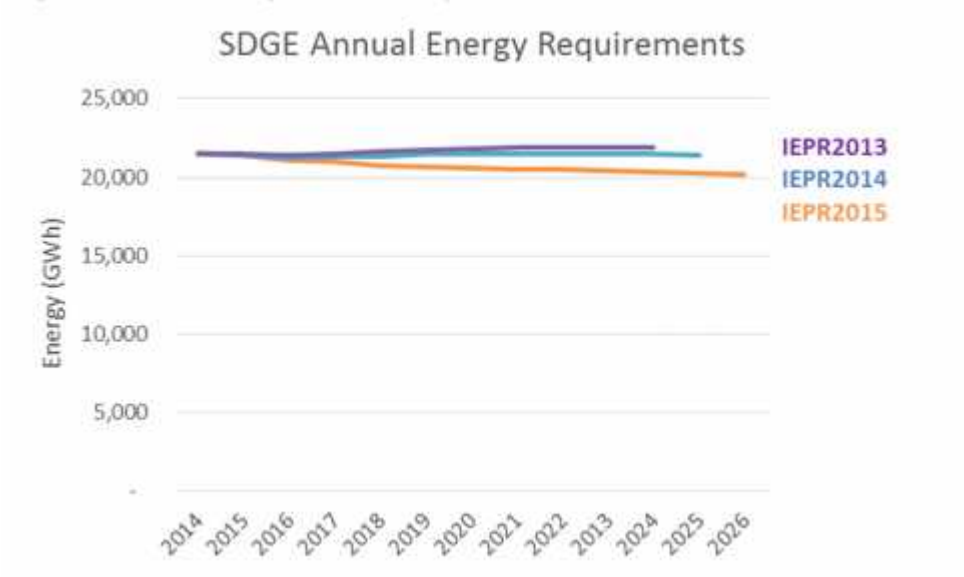

Table A-4: Installed BTM PV Capacity (MW)

	2016	2020
SCE	1301	2081
SDGE	453	755
PGE_VLY	976	1426
PGE_BAY	753	1101
Rest of CA	215	264
Total	3700	5628

Storage resources were modeled based on the CPUC Storage Target Decision (D.13-10-040), which forecasts 1,325 MW of storage resources in 2024[29] – this is reduced to 663 MW in 2020. The Scenario Tool only provides statewide installed capacity values – we held the proportion of storage resources in PGE, SCE, and SDGE constant and adjusted values downwards to reach the 2020 target. We did not believe the assumptions made in the Scenario Tool with regards to Storage resources were realistic – instead we used the more up-to-date PUC Order in Docket 14-10-045, approving the ISO

[29] This 1,325MW includes 50MW of storage in SCE authorized under Track 1.

utilities' procurement plans.[30] This order lists storage targets of 120MW for PG&E, 120MW for SCE, and 30MW for SDG&E for 2016.

Adjustments to demand response capacity are small – based on the Scenario Tool we removed 5 MW of DR resources that were planned to be installed between 2020 and 2024, leaving 2,171MW of DR available to the model.

The reduced loads in the 2020 case mean RPS requirements are also less. Based on the Scenario Tool and a 33% RPS target in 2024, our changes in load would result in a reduction of 200 MW of renewable resources. These were incorporated as reductions in California wind resources.

What forecast of natural gas prices did you use in your analysis?

We started with the gas model provided with the Energy Division report "Estimating Natural Gas Burner Tip Prices for California and the Western United States", published in November 2014, and modified prices based on preliminary results in the November 2015 Staff Report "2015 Natural Gas Outlook.[31,32] The model specifies burner-tip prices for 31 locations across the WECC.

Please describe in detail how you allocated capacity costs to hours across the year.

We used a loss of load expectation (LOLE) model to calculate the relative risk of a generation shortage in all hours of 2016 and 2020, taking into account uncertainty in both load and resource availability. This is the same framework used by SCE during its GRC Phase 2 rate case. We developed 30 possible peak and energy scenarios, and randomized daily wind and solar generation forecasts against load in each month. To calculate the relative LOLE in each hour, these net loads were compared against a distribution of thermal resource availability, including both forced and planned outages.

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[30] California Public Utilities Commission, Decision 14-10-045. October 16, 2014. "Decision Approving San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company's Storage Procurement Framework and Program Applications for the 2014 Biennial Procurement Period". pg 6.

[31] "Estimating Natural Gas Burner Tip Prices for California and the Western United States" California Energy Division Publication Number: CEC-200-2014-008. November 2014.

[32] California Energy Commission. "2015 Natural gas Outlook: Draft Staff Report". November 3, 2015. pg 21.

The model was populated with loads and resources consistent with our PLEXOS energy modeling. We produced two sets of model results – one for SDG&E's territory only and another for CAISO as a whole. The SDG&E model included a representation of the availability of transmission resources to serve SDG&E's load – we model this as two 1,750MW firm import paths. The CAISO model includes all resources in the CAISO area. We assume perfect transmission within the CAISO area, and five 1,900 MW paths (two to the North and three to the East), for a total of 9,500MW of capacity external to the system eligible for import. [33]

Please describe in detail how you develop the 30 hourly load profiles used in the LOLE analysis.

Thirty unique random scalars were generated for each day of the year – 1 for each profile. This random number was normally distributed with a standard deviation calculated based on the relative variation expected in each month. Each hour of the base load profile (the LTPP profile, adjusted for 2020), was adjusted by this scalar.

[33] CAISO. "2015 Summer Loads & Resources Assessment". May 7, 2015. pg 19. Available at: https://www.caiso.com/Documents/2015SummerAssessment.pdf. This indicates total "moderate" net interchange of 9,500 MW into CAISO.

CHAPTER 5

SALES FORECASTS

ERIC DURAN

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CHAPTER 5
SALES FORECASTS
ERIC DURAN

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

This chapter presents the Office of Ratepayer Advocates' ("ORA") recommendations on San Diego Gas and Electric Company's ("SDG&E") sales forecast for years 2016 through 2018. SDG&E updates its total sales forecast from its Test Year ("TY") 2016 General Rate Case ("GRC") Phase 1 Application ("A.") 14-11-003 based on the California Energy Commission's ("CEC") 2015 California Energy Demand ("CED") forecast.[1] Further, in compliance with SDG&E's most recent Phase 1 Decision ("D.") 15-05-040, SDG&E forecasts sales on an hourly and customer basis in support of its time-of-use ("TOU") periods proposal.

SDG&E also requests that the Commission approve the use of an annual advice letter to update electric sales forecasts beyond the test-year. SDG&E claims that more frequent updates to sales forecasts would reduce the impact of under/over-collections related to the differences between actual and test-year sales.[2]

Below are summaries of ORA's recommendations:

- ORA reviewed the method and data presented in SDG&E's updated sales forecasts and does not object to the total electric sales forecast of 19,680 Gigawatt hours ("GWh") for TY 2016.
- ORA supports SDG&E's proposal to update sales forecasts more frequently, and recommends that SDG&E continue to do so via the Energy Resource Recovery Account ("ERRA") Forecast proceeding, adopted in D.02-10-062. This venue already allows for a review of sales forecasts in relation to other components in the ERRA filing.

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[1] SDG&E , Prepared Testimony of Kenneth E. Schiermeyer p.5

[2] SDG&E , Prepared Testimony of Kenneth E. Schiermeyer p.9

- The Commission should reject SDG&E's proposal to use a stand-alone advice letter process to update its annual sales data.

II. DISCUSSION

A. Sales Forecast

SDG&E first made its TY 2016 sales forecast in its GRC Phase 1. In this GRC Phase 2 Application, SDG&E incorporates electric demand forecasts made by the CEC to obtain its sales forecasts.[3] The CEC's demand forecasts are adjusted by additional CEC forecasts for private supply and Additional Achievable Energy Efficiency ("AAEE"). As SDG&E explains in its testimony, the CEC completes a full update to its Integrated Energy Policy Report ("IEPR") every two years with limited updates in the interim years.[4] Table KS-3 of SDG&E's testimony (reproduced below as Table 5-1) shows the sales updates being requested in this proceeding.[5]

Table 5-1

Electric Sales Forecast Derivation, Total System (GWh)

	GRC Phase 1 TY 2016	**GRC Phase 2 TY 2016**	**Change**	**% Change**
Consumption	21,855	21,691	-161	-0.8%
Less: Private Supply	1,301	1,513	212	16.3%
Less: AAEE	541	498	-43	-7.9%
Equals: Sales	**20,013**	**19,680**	**-333**	**-1.7%**

For 2016 sales forecasts, SDG&E disaggregates the total sales forecasts by customer classification on an hourly basis. This data is necessary for allocating

[3] Specifically, SDG&E used the CEC's 2014 CED Updated Forecast, mid-demand consumption scenario as the basis of its sales forecasts.

[4] SDG&E , Prepared Testimony of Kenneth E. Schiermeyer p.4

[5] SDG&E , Prepared Testimony of Kenneth E. Schiermeyer p.7

customer revenue responsibility based on different TOU periods once defined. SDG&E's process to develop its hourly TY sales forecast incorporates historical sales data for 2013 and 2014. SDG&E estimates TY load shapes using a multivariate ordinary least squares ("OLS") regression method. Examples of the variables SDG&E used include heating and cooling degree days, the average fraction of daylight during a given day of the year, and temporal characteristics such as holidays and daylight savings time. The exact variables are dependent on the specific customer classification regression model.[6] ORA reviewed the model specifications and, at this time, does not raise any objections to SDG&E's regression methodology. SDG&E's methodology is based on reasonable forecasting assumptions, OLS, and variables that have been previously adopted by the Commission.[7]

SDG&E's regression-estimated sales forecasts initially do not match the CEC's total forecasts. This is because the regression-estimated sales forecasts, derived from SDG&E's sales data, are used solely for the purpose of estimating load shape.[8] SDG&E later scales the regression sales forecasts results to equal the CEC's total forecast which preserves the regression-estimated load shape. This process is done using Itron's MetrixLT Software v4.5.[9] The calibration results are comparable to the simpler method of adjusting sales such as scaling hourly sales by the ratio of regression total sales to CEC total sales. ORA does not object to

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[6] SDG&E workpaper "SDGE-4_KSCHIERMEYER_WP_Part_3_Res.xlsx" tab "Stata code" shows that a different set of variables are used for each model depending on the customer class being modeled.

[7] For example, PG&E lists exogenous variables in the confidential workpaper "GRC2011Workpapers Ex8 Ch04 confidential.xls" filed in its Rate Design Window proceeding A.10-02-028. See section B.1 below for a discussion on SCE's sales forecast methodology.

[8] SDG&E uses recorded sales data on an hourly basis to estimate the 2016 load shape. The CEC currently does not forecast sales on an hourly basis.

[9] SDG&E Confidential workpaper "SDGE-4_KSCHIERMEYER_WP_Part_5 HRCalibrate (Confidential).xlsx"

SDG&E's method of disaggregating total sales into hourly and customer components.

B. Request for Annual Sales Forecast Update through an Advice Letter

As SDG&E's most recent ERRA Forecast proceeding Decision states, the ERRA regulatory process includes, "(1) an annual forecast proceeding to adopt a forecast of the utility's electric procurement cost revenue requirement and *electricity sales for the upcoming year*, and (2) an annual compliance proceeding to review the utility's compliance in the preceding year regarding energy resource contract administration, least cost dispatch, fuel procurement, and the ERRA balancing account [emphasis added]."[10] SDG&E should continue to use the ERRA Forecast proceeding as the appropriate regulatory venue to update sales forecasts.

SDG&E should incorporate current data and forecasts available at the time of future ERRA Forecast filings. This allows 2017 and 2018 sales forecasts to be based on updated data. SDG&E's request for the Commission to adopt total sales forecasts for 2017 and 2018 in this GRC Phase 2 proceeding would not allow for updates in data or methodology. Finally, SDG&E's request to update sales in an advice letter is beyond the scope of matters appropriate to advice letters because it lacks sufficient opportunity for party review, and has the ability to significantly affect customer bills.

1. Established ERRA Forecast Proceeding

The ERRA proceeding established in D.02-10-062 allows the energy IOU's to track fuel and purchased power billed revenues against actual recorded costs. Other utilities make use of the ERRA Forecast proceeding to make annual updates

[10] Decision 15-12-032, pp. 3-4

to their sales forecasts. For example, both SCE's and PG&E's 2015 ERRA Forecast filings requested updates to electric sales.[11], [12]

In SCE's application filing, A.15-05-007 Exhibit SCE-01, SCE included a chapter supporting their sales forecast updates. Contained within this chapter is an examination of the various factors influencing sales. SCE focused their analysis on the historic and forecasted conditions of economic activity, weather, energy efficiency programs, and self-generation. This type of analysis which appropriately supports sales forecast updates is an example of how SDG&E can perform, in its ERRA Forecast proceeding, their request of updating sales annually.

The ERRA Forecast proceeding already provides an opportunity to review and update sales forecasts. Further, updating electric sales forecasts in the ERRA Forecast proceeding would allow for intervenor review of sales forecast methods or data sources used in the formation of forecasts. The advice letter process is neither an appropriate venue for a review of sales forecast updates nor would it allow for improvements in sales forecasts to be made.

2. Forecasts based on Current and Verifiable Data

In future ERRA Forecast filings, SDG&E should include a comprehensive breakdown of their forecast proposal including the data sources and methodology. This methodology can be explained by the company during a workshop in the ERRA Forecast proceeding focused on sales forecast updates and procurement related issues.[13] The method implemented and data used to conduct future hourly load shape estimates should be presented during this workshop as well. Just as in SDG&E's filing in this GRC Phase 2 proceeding, the company should utilize the

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[11] SCE's ERRA proceeding, A.15-05-001, Exhibit SCE-01 p.9

[12] PG&E's ERRA proceeding, A.15-06-001, p.1

[13] For example, SDG&E in the past has held workshops focused on detailed explanations of their triggered ERRA balance and specific requests for a revenue requirement adjustment. See the amendment to A.12-04-003 filed April 9, 2012, p.2

most current forecasts and data available at the time. This would allow the company and intervenors to reassess the impact of behind the meter effects, such as photovoltaics ("PV") and electric vehicle ("EV") adoption rates, on electricity sales on a timely basis.

3. Advice Letter Process

Advice letters are typically reserved for utilities to address ministerial implementation issues. The process of updating sales does not fit that framework. General Rule 5.1 of General Order 96-B states that "[t]he advice letter process provides a *quick and simplified review* of the types of utility requests that are expected neither to be controversial nor to raise important policy questions [emphasis added]." Because sales forecast methodologies can vary based on when forecasts are made and that changes to sales results in rate impacts, the Commission should not limit the methodology to a rigid formula or predefined numbers as SDG&E has suggested. In the past, intervenors have often objected to sales forecasts provided by the utility.[14] Further, the Commission has rightly assessed that accurate and reliable forecasts are an important part of the evidentiary record for approving TOU rates.[15] As TOU rates become prevalent, an appropriate venue for updates to sales forecasts will be necessary to build an evidentiary record. Updating sales through the advice letter process would not allow for review beyond what can be considered quick and simplified.

III. CONCLUSION

ORA does not take issue with SDG&E's method for determining total electric sales forecasts and the process by which the company disaggregates total

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[14] Examples of such objections can be found in D.13-05-010 where the Utility Consumers' Action Network ("UCAN") contends that SDG&E forecasts were unrealistic, D.14-08-032 where then DRA challenged PG&E's electric sales forecast for plug-in electric vehicles, and D.14-12-053 where PG&E was ordered to include additional sales data for agricultural customers in its ERRA Forecast proceeding.

[15] Scoping Memo and Ruling of Assigned Commissioner and Assigned Administrative Law Judge, R.15-12-012, filed May 3, 2016, pp.6-7

sales into hourly sales forecasts. SDG&E's request to update sales forecasts annually through an advice letter is inappropriate as the subject issue is likely to be controversial or raise important policy questions while not allowing for adequate review. Furthermore, the existing ERRA Forecast proceeding provides an appropriate forum to incorporate sales updates.

CHAPTER 6

REVENUE ALLOCATION

AARON LU

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CHAPTER 6

REVENUE ALLOCATION

AARON LU

I. INTRODUCTION

This chapter addresses the Office of Ratepayer Advocates' ("ORA's") proposals for allocating generation, distribution, and a variety of miscellaneous costs to customer classes. ORA provides its analysis of San Diego Gas and Electric Company's ("SDG&E") proposals and explanations of ORA's recommendations.

II. SUMMARY OF RECOMMENDATIONS

ORA recommends using a marginal cost based revenue allocation methodology in this General Rate Case ("GRC") Phase 2 proceeding. This is consistent with the Commission's long-standing policy since the late 1970s, This revenue allocation methodology is applied to generation and distribution revenue requirements, which constitute 80.36 percent of the overall revenue requirement.[1] ORA's adjustments to SDG&E's marginal cost estimates in Chapters 1 through 4 are incorporated into its revenue allocation analysis.

ORA also recommends setting Time-of-Use ("TOU") periods with a 4 pm to 9 pm on-peak period on weekdays only with all other hours of the week and all hours on weekends/holidays off-peak. The summer season is from July to October and winter season from November to June. In addition, the Commission should adopt the all Loss of Load Probability ("LOLP") hours for allocating marginal generation capacity cost and establishing the TOU periods.

Miscellaneous revenue responsibilities include Public Purpose Programs ("PPP"), the Competitive Transition Charge ("CTC"), the Local Generation

[1] SDG&E's Consolidated Model GRC Phase 2 – ORA Workpaper, tab "Class Avg Rev Adj - Year 3"

Charge ("LGC"), Demand Response ("DR"), the California Solar Initiative ("CSI"), and the Self-Generation Incentive Program ("SGIP"). Public Purpose Programs include California Alternative Rates for Energy ("CARE"), Energy Efficiency ("EE"), Energy Savings Assistance Program ("ESAP"), and the Electric Program Investment Charge ("EPIC").

ORA proposes using an equal cents per kilowatt hour ("kWh") allocator or a total sales percentage allocator for SGIP and using an equal cents per kWh allocator for CSI, exempting CARE customers. SDG&E has proposed to continue their policy allocating these costs based on each customer class's share of distribution costs.

ORA recommends caps and floors for the class average rates to mitigate rate volatility and adverse bill impacts.

All of the aforementioned changes contribute to the final allocation and to how ORA's proposed rates deviate from those proposed by SDG&E. In summary, ORA recommends the Commission adopt:

1. ORA's marginal costs to allocate revenue responsibilities;
2. ORA's proposed TOU periods;
3. All LOLP hours for marginal generation capacity cost allocation;
4. Equal cents per kWh allocator for the SGIP;
5. Equal cents per kWh allocator for CSI costs (with an exemption for CARE customers); and
6. ORA's caps and floors for class average rates in the proposed revenue allocation.

Table 6-1 below compares ORA's proposed revenue allocation to SDG&E's and Table 6-2 below contrasts ORA's proposed class average rates to SDG&E's.

Table 6-1: Total Revenue Allocation[2]

		SDG&E		ORA	
	Current Revenue ($000)	Proposed Revenue ($000)	Proposed Revenue (%)	Proposed Revenue ($000)	Proposed Revenue (%)
Residential	1,712,510	1,915,920	7.33%	1,812,463	5.84%
Small Commercial	474,694	512,531	3.58%	498,612	5.04%
Med&Lg C&I	1,587,142	1,508,988	-8.79%	1,624,898	2.38%
Agriculture	56,148	53,546	-8.51%	56,671	0.93%
Lighting	18,182	20,663	9.03%	19,015	4.58%
System Total	3,848,676	4,011,647	4.06%	4,011,657	4.23%

Table 6-2: Total Class Average Rate

		SDG&E		ORA	
	Current Total Rate (¢/KWhr)	Proposed Total Rate (¢/KWhr)	Total Rate Change (%)	Proposed Total Rate (¢/KWhr)	Total Rate Change (%)
Residential	22.943	25.649	11.79%	24.272	5.79%
Small Commercial	23.798	25.693	7.96%	25.002	5.06%
Med&Lg C&I	19.977	19.116	-4.31%	20.428	2.26%
Agriculture	17.886	17.153	-4.10%	18.171	1.59%
Lighting	19.726	22.420	13.66%	20.631	4.59%
System Total	21.443	22.346	4.21%	22.345	4.21%

III. DISCUSSION

A. ORA's Marginal Cost Revenue Allocation Recommendation

Revenue allocation is the process of assigning a portion of the utility's total revenue requirement to each customer class. Since the late 1970s, the Commission

[2] There is a difference of $162,971,826 (4.23%) between SDG&E's proposed and current total revenues. After ORA reached out to SDG&E, SDG&E responded on May 19, 2016 that the difference can be accounted for in different sales underlying the two scenarios, in moving SGIP and CSI revenues from distribution revenue to PPP revenue, and in unadjusted Federal Energy Regulatory Commission ("FERC") related rates in transmission revenue.

has used marginal cost based revenue allocation.[3] The process starts with calculating marginal costs for utility functions of generation and distribution.[4] Then the cost responsibility is assigned to customer classes based on the proportion of each class' marginal cost revenue relative to the total system marginal cost revenues.[5]

In Decision ("D.") 97-08-056, the Commission adopted the practice of allocating the revenue requirements of each individual function, generation and distribution, separately. Thus, the corresponding revenues are allocated on an unbundled basis using the separate marginal cost revenues for each function. This method determines each customer class' revenue responsibility by function based on the marginal cost revenue assigned to the class. An Equal Percent Marginal Cost ("EPMC") allocation[6] scales the latter up or down to match the authorized revenue requirement for each of the functions.

The marginal cost revenue is calculated by multiplying the functional marginal cost by the Marginal Demand Measures ("MDMs"). Marginal costs include marginal generation energy costs, marginal generation capacity costs, marginal distribution demand costs, and marginal distribution customer access costs. MDMs include measurement of each class' energy consumption, demand during the system peak, demand during the non-coincident peak, and the number of customers.

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[3] Decision 92549, Section B1: Staff Position on Marginal Cost Pricing; D.92-12-058, p.7 and p.20; D.92-12-057, p.4; D.15-07-001, Page 28, Rate design principle: Rates should be based on marginal cost.

[4] Since the electric industry restructuring of the late 1990s, most transmission is regulated by FERC.

[5] The marginal cost revenue is the revenue that would be produced if each customer were charged the marginal cost.

[6] Transmission revenue is set separately by FERC.

In this proceeding, SDG&E proposes to continue using the same method for marginal cost allocation, where the generation (or commodity) and distribution functions are allocated separately using the EPMC method,[7] and ORA concurs.

B. Marginal Generation (or Commodity) Cost Revenue

There are two generation-related cost functions. The marginal generation energy cost refers to the incremental cost of adding an additional unit (i.e. kWh) of energy consumption to the grid. The marginal generation energy cost is discussed in Chapter 1 of ORA's testimony. The marginal generation capacity cost measures the incremental cost imposed on the grid of adding an additional kilowatt ("kW") of demand. The marginal generation capacity cost is discussed in Chapter 2 of ORA's testimony. Mathematically, the marginal generation cost revenues can be expressed below:

Marginal generation energy cost revenue $_i$ = Σ Energy consumption in each TOU period by customer class i * Marginal generation energy cost by Time-Of-Use (TOU) period

Marginal generation capacity cost revenue $_i$ = Σ Class i's MW demand during the system's top 250 hours demand * Marginal generation capacity cost

Table 6-3 below is ORA's proposed marginal generation (or commodity) cost revenue allocation in contrast to those of SDG&E's.

[7] SDG&E proposes to allocate its Commission-jurisdictional revenue requirements for

(continued on next page)

Table 6-3: Generation Revenue Allocation

		SDG&E		ORA	
	Current Revenue ($000)	Proposed Revenue ($000)	Proposed Revenue (%)	Proposed Revenue ($000)	Proposed Revenue (%)
Residential	832,849	898,076	7.83%	866,549	4.05%
Small Commercial	205,269	217,730	6.07%	224,439	9.34%
Med&Lg C&I	713,561	700,774	-1.79%	723,312	1.37%
Agriculture	28,144	30,413	8.06%	32,688	16.15%
Lighting	6,938	8,957	29.09%	9,372	30.07%
System Total	1,786,760	1,855,949	3.87%	1,856,359	3.90%

1. ORA's Proposed Time-of-Use Periods Recommendation

ORA recommends that the Commission adopt Time-of-Use ("TOU") periods that consists of a 4 pm to 9 pm on-peak period on weekdays only and all other hours on weekdays and weekends and holidays considered off-peak. Summer season is from July to October and winter season from November to June.

ORA defines the TOU periods primarily based on grouping hours with similar hourly marginal costs into the same TOU periods. ORA's proposed TOU design is supported by ORA's production cost and loss of load expectation modeling results. Modeling results show significantly higher marginal generation costs for the proposed on-peak period for summer weekdays than for summer weekends. Thus, ORA groups the weekday 4 pm to 9 pm as the on-peak period and all the other hours on weekdays and all hours during weekends and holidays as the off-peak period. Chapter 4 provides more detailed results to support this proposal.

In addition, ORA also considers the administrative feasibility and customer understanding of TOU periods. Residential customers may have difficulty shifting

(continued from previous page)
distribution and generation services based on its marginal costs. (Ex. SDG&E-103, p.WGS-1.)

their energy use away from the SDG&E's proposed 4 pm to 9 pm on-peak period every single day of the year (on both weekdays and weekends). Considering customer acceptance, ORA thus proposes an on-peak period from 4 pm to 9 pm on weekdays only for customers to gradually get accustomed to TOU periods. SDG&E's abrupt switch may confuse customers or lead to undesirable customer reactions to TOU rates.

2. Incorporate All Loss of Load Probability Hours

ORA applies all 8,760 Loss of Load Probability ("LOLP") hours for allocating marginal generation capacity cost in contrast to SDG&E's approach of only looking at the top 100 LOLP hours. ORA's method better aligns the marginal generation capacity cost and covers all LOLP occurring throughout the entire year because it looks at every hour in the year. ORA's proposed all LOLP hours are derived from Synapse's loss of load modeling results. The derivation and impact of Synapse's utilization all LOLP hours are described in more detail in Chapters 3 and 4.

C. Marginal Distribution Cost Revenue

There are also two distribution-related cost functions; those associated with providing customer access to the grid, and those with meeting non-coincident customer demand on the distribution system. ORA presents different marginal customer access and demand cost proposals than those presented by SDG&E, as explained in Chapters 3 and 4. ORA uses the New Customer Only ("NCO") method, while SDG&E uses the Rental method in quantifying marginal access costs. In the NCO method, the MDM is the number of new customers. In contrast, in the rental method, the MDM is the total number of customers. Mathematically, the marginal distribution cost revenues are expressed as follows:

Marginal distribution demand cost revenue $_i$ = Σ Class i's non-coincident peak demand[8] * Marginal distribution demand cost

Marginal customer access cost revenue $_i$ = Σ Number of customers for customer class i * Marginal customer access cost per customer per year for class i[9]

Table 6-4 below is ORA's proposed marginal distribution cost revenue allocation compared to SDG&E's.

Table 6-4: Distribution Revenue Allocation

		SDG&E		ORA	
	Current Revenue ($000)	Proposed Revenue ($000)	Proposed Revenue (%)	Proposed Revenue ($000)	Proposed Revenue (%)
Residential	658,705	717,539	8.93%	685,103	4.01%
Small Commercial	179.659	202,611	12.78%	183,269	2.01%
Med&Lg C&I	507,069	422,923	-16.59%	476,163	-6.09%
Agriculture	20,380	15,345	-24.71%	14,908	-26.85%
Lighting	8,915	9,193	3.12%	7,687	-13.77%
System Total	1,374,727	1,367,610	-0.52%	1,367,132	-0.55%

In summary, ORA's proposed marginal cost revenues are different from SDG&E's proposals because of the different assumptions and methods used for the marginal costs calculations.

D. Miscellaneous Revenue

In addition to marginal generation cost and marginal distribution cost revenues, miscellaneous revenue responsibilities include Public Purpose Programs ("PPP"), the Competitive Transition Charge ("CTC"), the Local Generation Charge ("LGC"), Demand Response ("DR"), the California Solar Initiative

[8] Non-coincident peak is the maximum demand of a customer class regardless of when the system peak occurs.

[9] Even though ORA's NCO uses one time total hook-up costs for new customers, the numbers are converted to per customer as comparable to the Rental in the model.

("CSI"), and the Self-Generation Incentive Program ("SGIP"). Public Purpose Programs include California Alternative Rates for Energy ("CARE"), Energy Efficiency ("EE"), Energy Savings Assistance Program ("ESAP"), and the Electric Program Investment Charge ("EPIC").

1. Allocate The Self generation Incentive Program and the California Solar Initiative on Equal Cents per Kilowatt Hour Allocators

SDG&E proposes to recover Self Generation Incentive Program ("SGIP") and California Solar Initiative ("CSI") costs from Public Purpose Program ("PPP") rates rather than in distribution rates. SDG&E states that there is no proposal to change the current cost responsibility and allocation treatment of these program costs and thus, there will be no rate impact from recovering the costs from PPP rates rather than from distribution rates.[10] SDG&E proposes to continue using distribution EPMC allocation to recover SGIP and CSI costs.

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 program that, "The self-generation programs … will produce significant public (e.g., environmental) benefits for all ratepayers."[11] 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."[12] 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."[13] The Commission has

[10] A.15-04-012, SDG&E's Testimony Chapter 2 Christopher Swartz, p.CS-18

[11] D.01-03-073, mimeo, Finding of Fact #3, p.40.

[12] D.06-01-024, mimeo, p.12.

[13] Ibid, Finding of Fact #5, p.39.

consistently allocated the costs of these types of programs based on sales, using equal cents per kWh or therm allocation. For these reasons, ORA proposes that SGIP and CSI to be allocated on an equal cent per kWh basis.

In the past, the Commission has decided to allocate the costs of similar programs on a volumetric basis by sales.[14] In a 2007 Biennial Cost Allocation Proceeding, the Commission made another determination that gas SGIP costs should be allocated volumetrically.[15]

ORA also notes that the Commission has exempted CARE customers from paying for the CSI program. In the CSI program adoption decision, the Commission states: "We do, however, exempt CARE customers from the costs of this program as a matter of equity, especially since CARE customers are the least likely to be beneficiaries of the incentives."[16]

Table 6-5 below shows ORA's proposed SGIP and CSI allocators compared to SDG&E's.

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[14] Regarding the Natural Gas Vehicle Program ("NGV"), the Commission concluded:

> The Legislature has declared that the pursuit of cleaner air and relief from global warming is in the public interest. There is nothing in the hearing record which suggests that these benefits, as well as the strategic advantage of lowering our dependence upon foreign oil, will not be realized by the successful implementation of this program. To the extent that they are, they will be enjoyed by all Californians in their capacity as ratepayers, D.91-07-018, 40 CPUC 2d, p.738-739.
>
> The fixed infrastructure costs associated with the NGV program result in air quality benefits enjoyed by all Californians in their capacity as ratepayers and, as such, should be recovered on **an equal cents per therm basis** over all volumes sold by PG&E to all customer classes consistent with the intent of Public Utilities Code 740.3(c).149, Ibid, 40 CPUC 2d at 744, Finding of Fact #13.

[15] Consistent with our view that all customers should pay for programs that provide environmental benefits, we include wholesale customers in the allocation of SGIP costs as well as EG customers and adopt PG&E's proposal to allocate the costs on an equal cents per therm basis, D.05-06-029, mimeo, p.18.

[16] D.06-01-024, mimeo, p.19–20

Table 6-5: SGIP and CSI Revenue Allocator

		SGIP		CSI	
		SDG&E	**ORA**	**SDG&E**	**ORA**
	Current Allocator (%)	Proposed Allocator (%)	Proposed Allocator (%)	Proposed Allocator (%)	Proposed Allocator (%)
Residential	41.5%	41.5%	38.2%	41.5%	34.1%
Small Commercial	11.4%	11.4%	10.1%	11.4%	10.7%
Med&Lg C&I	46.1%	46.1%	49.6%	46.1%	52.9%
Agriculture	0.5%	0.5%	1.6%	0.5%	1.8%
Lighting	0.5%	0.5%	0.5%	0.5%	0.5%
System Total	100.0%	100.0%	100.0%	100.0%	100.0%

In summary, ORA recommends that the Commission continue this policy of allocating the costs of SGIP and CSI to all customer classes on an equal cents per kWh basis and that CARE customers should not be allocated CSI costs.

E. Adopt Caps and Floors Class Average Rates

The Commission has consistently adopted caps on the revenue allocation to moderate the movement towards full marginal cost rates. This policy continues to be reasonable at the present time. In SCE's 1995 GRC Phase 2 Decision (D.96-04-050), the Commission provided an extensive discussion of the policy of capping, including citing a number of proceedings where capping was adopted:

> In the past, we have capped full movement to 100% EPMC in order to mitigate harsh bill impacts. In Edison's last GRC, we determined that average rate increases of approximately 20% to the agricultural and pumping class should be mitigated by imposing a cap of SAPC plus 3.5%. In Edison's test year 1988 GRC, we capped full EPMC revenue allocation by SAPC plus 5% to mitigate increases to the domestic class of a similar magnitude.[17]

ORA propose to apply caps and floors on the revenue requirement changes such that the class average rate will not exceed the system average rate change

[17] D.87-12-066 26 CPUC 2d 392, p.528-529; D.92-06-020, p.44 CPUC 2d 471, p.496-497

plus at 1.5 percent to mitigate rate volatility and adverse bill impacts for all customer classes. ORA's proposal to cap and floor class level increases is reasonable given that a considerable number of past Commission decisions have limited class-revenue changes within a similar range.[18]

Table 6-6 below shows ORA proposed system average rates with and without a capping and flooring mechanism.[19] If the proposed system average rates are uncapped, there will be a 8.09 percent increase from current total rate to proposed total rate for the residential class. The small commercial class will see the impact of a 5.33 percent increase. ORA proposes to cap and floor revenue requirement changers to each class such that the class average rate change will not exceed the system average rate change plus 1.5 percent. If a capping and flooring mechanism is implemented, the increases for the residential and small commercial total rates will be 5.79 percent and 5.06 percent, respectively. Other changes, not stemming from this proceeding, such as residential rate reform tier collapsing for residential class customers and mandatory TOU rates and default critical peak pricing for small commercial customers will result in higher bills for most residential and small commercial customers in the near future. Thus, a capping and flooring mechanism will mitigate the increase in rates resulting from the compounding and upcoming anticipated changes.

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[18] See *So. Cal. Edison*, D.96-04-050, 65 CPUC2d 362, 1996 Cal. PUC LEXIS 270, at p.128–134 (dated Ap. 10, 1996), for a discussion of Commission policy on capping. Also, in SDG&E's 2000 Rate Design Window ("RDW") the revenue allocation was capped at SAPC plus or minus three percent. *SDG&E*, D.00-12-058, 2000 Cal. PUC LEXIS 1013, p.44-46 (Dec. 21, 2000). In Pacific Corp's 2003 GRC, the Commission granted an overall system average increase of 4.7 percent plus a cap of 2.5 percent. See *PacifiCorp.*, D.03-11-019, D. 03-11-019, 2001 Cal. PUC LEXIS 1266, at p.14–15 (Finding of Fact 3) (dated Nov. 13, 2003). In Sierra Pacific's 2003 GRC, the Commission granted an increase of 6.2 percent plus a cap of 2.6 percent. See *Sierra Pacific*, D.04-01-027, 2001 Cal. PUC LEXIS 1281, at p.12–13 (dated Jan. 8, 2004).

[19] SDG&E's Consolidated Model for ORA TOU Scenario 2 does not cap and floor system average rate for all customer classes but rather caps and floors distribution and generation revenue allocations separately. ORA ran the model with a 3% cap for Residential Class Distribution Allocation and a 2.3% cap for Small Commercial Class Distribution Allocation and with a 2.9% cap on Residential Class Commodity Allocation, a 7% cap on Small Commercial Class Commodity Allocation, and a 5% cap on Street lighting Class Commodity Allocation. The capping setup reaches an approximate system average rate plus 1.5% cap and floor for Residential and Small Commercial classes indirectly.

Table 6-6: Total Revenue Allocation With and Without Cap and Floor

		ORA With 1.5% Cap and Floor		ORA Without Cap and Floor	
	Current Total Rate (¢/KWhr)	Proposed Total Rate (¢/KWhr)	Total Rate Change (%)	Proposed Total Rate (¢/KWhr)	Total Rate Change (%)
Residential	22.943	24.272	5.79%	24.798	8.09%
Small Commercial	23.798	25.002	5.06%	25.067	5.33%
Med&Lg C&I	19.977	20.428	2.26%	20.009	0.16%
Agriculture	17.886	18.171	1.59%	17.776	-0.62%
Lighting	19.726	20.631	4.59%	21.237	7.66%
System Total	21.443	22.345	4.21%	22.347	4.22%

IV. CONCLUSION

ORA recommends that revenue allocation be based on ORA's proposed marginal costs. The Commission should adopt ORA's proposed TOU design and adopt the all LOLP hours for allocating marginal generation capacity cost. SGIP and CSI costs should be allocated based on equal cents per kWh allocators, but CARE customers should be exempted from the CSI allocation. Finally, ORA recommends that the Commission adopts ORA's proposed caps and floors for revenue allocation to mitigate bill volatility and adverse bill impacts.

CHAPTER 7

RESIDENTIAL RATE DESIGN

CHERIE CHAN

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CHAPTER 7

RESIDENTIAL RATE DESIGN

CHERIE CHAN

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Office of Ratepayer Advocates' ("ORA") recommendations in San Diego Gas and Electric's ("SDG&E") General Rate Case Phase 2 ("GRC2") Proceeding.

ORA recommends:

1. SDG&E's residential rates should be based on the rates adopted in Resolution E-4787 as a starting point, and as the basis for future tier 1 rate increases.
2. The residential rates from Resolution E-4787 should be escalated by ORA's proposed revenue allocation to the residential class.
3. Residential baseline (Tier 1) rate increases should be capped at the residential average rate change +5% (relative to rates for the prior twelve months), which will continue to allow progress in narrowing the differential between tier 1 and tier 2 rates.
4. Rate changes should be consolidated to reduce customer confusion.
5. The Commission should adopt ORA's Time of Use ("TOU") period recommendations: these TOU periods should remain constant for five years, or two GRC cycles, but CPP event periods may change more frequently.

II. BACKGROUND

This Application represents SDG&E's first General Rate Case Phase Two since Decision (D.)15-07-001 (the Decision)in Rulemaking (R.)12-06-013 in the Residential Rate Reform Rulemaking, R.12-06-013.[1] This Decision marked the

[1] Decision 15-07-001, D.15-7-001, or the Decision.

"culmination of a three-year long examination of proposed rate reforms for the three major investor-owned utilities in California".[2] As such, SDG&E claims that it:

> makes no new proposals in this proceeding to make adjustments to residential tiered rates but does reflect compliance with D.15-07-001 in the residential rates presented in this filing.[3]

ORA agrees with SDG&E that an extensive record has been developed in R.12-06-013[4], and that issues that have clearly been decided by the Commission should not be re-litigated in this case. In this proceeding, SDG&E filed their Second Amended Application on February 29th, 2016. Since then, the Commission has issued two rulings which reaffirm and clarify the Decision's intent with respect to the glidepath towards a more mildly-differentiated two-tiered rate.

First, Judge Jeanne McKinney put forth a ruling on March 14, which sets clear price caps on Tier 1 rate increases, even if this would change the shape of the tier-flattening glidepath. The Commission reaffirmed its intent again on May 26th through Resolution E-4787. This resolution approves an increase to Tier 1 rates while still making forward progress towards tier consolidation. The rates ordered in this resolution should also act as the basis for Tier 1 increases capped at 5% plus RAR while moving forward along the tier-flattening glidepath set forth by the Decision. Within this context, ORA recommends that SDG&E proceed cautiously and deliberately with proposed rate changes, especially for its smallest customers.

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[2] D.15-7-001, page 1.

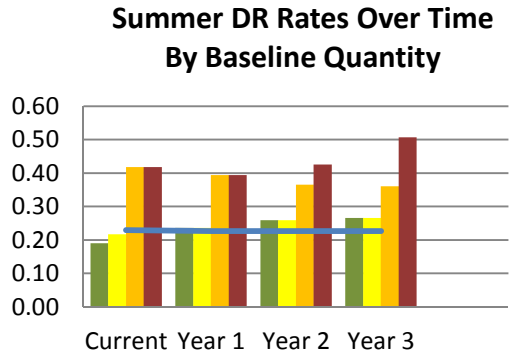
[3] Exhibit SDG&E-02. Prepared Direct Testimony of Christopher Schwartz, CS-5, lines 10—12. February 9, 2016.

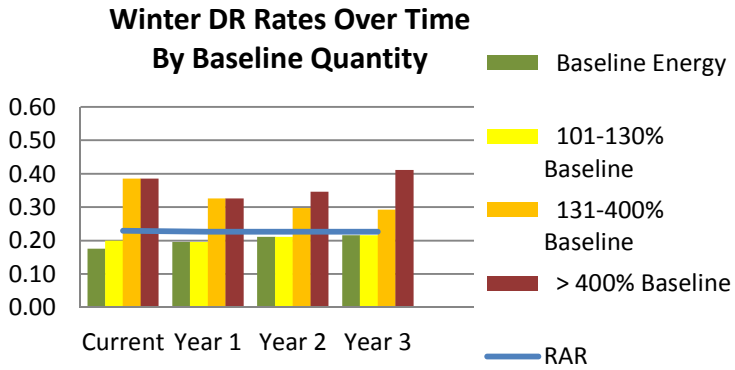
[4] R.12-06-013: SDG&E Notice of Ex Parte Communication, received Thursday, May 19, 2016 at 3:37 PM.

III. SDG&E'S PROPOSED RATES

A. SDG&E's Proposed Rates will Result in Large Year over Year Increases for Smaller Customers while Benefitting a Few Larger Customers

SDG&E's rate proposals, as shown in the illustrated summer rates below, assume that the Residential Average Rate ("RAR") decreases slightly over time. Even so, SG&E's proposals will result in large year-over-year rate increases that primarily affect smaller customers over the next few years, but moderate over time as the Decision's tier consolidation directives are implemented. Very large users will receive sharp decreases in the near-term—especially in the winter— through tier consolidation. High user rates will eventually rise again with the introduction of the Super User Surcharge ("SUE"), as shown in the graphs of SDG&E's proposed rates below.[5]





[5] Source: ORA Workpaper Titled "0_ORA_Compare", tab "1_YOY Changes". The numbers in this set of charts are derived from SDG&E's workpapers supporting SG&E's Second Amended Application, dated February 9th, 2016. ORA's version used in the tables and chart below aggregate and display SDG&E's proposed rate changes over time to demonstrate the effects of tier-flattening.

SDG&E's proposed rates over time, assuming no system revenue changes, are shown in the table below.[6] SDG&E shows rate proposals for three years because their proposed revenue allocation would be phased in over a three-year period. ORA follows normal general rate case practice and only proposes rates for one year, based on ORA's proposed revenue allocation.

TABLE 1: SDG&E'S PROPOSED RATES

		Proposed Rate		
SCHEDULE DR	Current	Year 1	Year 2	Year 3
Baseline Energy	0.19031	0.23613	0.25862	0.26547
101-130% Baseline	0.21656	0.23613	0.25862	0.26547
131-400% Baseline	0.41778	0.39395	0.36504	0.36030
> 400% Baseline	0.41778	0.39395	0.42531	0.50672
Winter Energy				
Baseline Energy	0.17542	0.19558	0.21069	0.21562
101-130% Baseline	0.19961	0.19558	0.21069	0.21562
131-400% Baseline	0.38509	0.32629	0.29738	0.29264
> 400% Baseline	0.38509	0.32629	0.34649	0.41156
Minimum Bill	0.32900	0.32900	0.32900	0.33600

B. A Comparison of Rates under SDG&E and ORA's Marginal Cost and Revenue Allocation Proposals

As discussed in the previous six chapters, ORA makes several changes to SDG&E's Marginal Cost and Revenue Allocation proposals, which ultimately impact the structure of each rate. ORA presents the rate impacts of these Marginal Cost and Revenue allocation recommendations only, so decision-makers can understand the affect ORA's changes have on rates. The effects of these rate impacts on each of SDG&E's many residential rates are described in detail in ORA's workpapers,[7] and excerpted for SDG&E's default Domestic Residential ("DR") rate schedule below.

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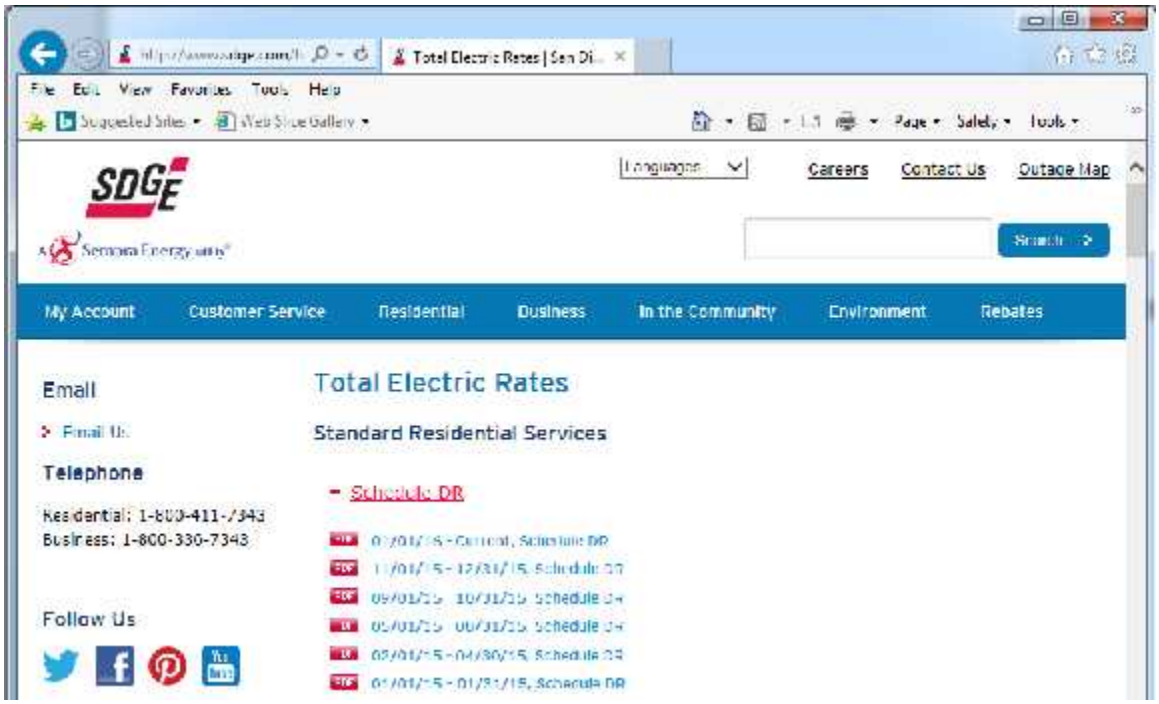
[6] Id.

[7] Filename 0_ORA_Compare, tab "1-2_SDGE to ORA MC RA".

IV. ORA'S RATE DESIGN PROPOSALS

A. The Commission Provides the SDG&E with a Clear Guidepost for Resetting Rates and a Direction for Moving Forward

ORA recommends that SDG&E follow the Commission's general guidance that meaningful year-over-year rate analyses should be based on the billing rate from twelve months prior. Over the past year, customers have faced several rate changes and some uncertainty as evidenced by the continued suspension of SDG&E AL-2784-E filed September 1, 2015. As of June 1, 2016, SDG&E's Tariff Book,[8] reveals five changes to the DR tariff sheets in 2015 alone, which further contributes to customer confusion and rate unpredictability.



Most recently, the Commission released Resolution E-4787[9], which fairly balances the competing goals of the Decision's approved glidepath of collapsing tiers while allowing moderate price increases for lower-tier customers. ORA

[8] See the website: http://www.sdge.com/total-electric-rates

[9] Resolution E-4787 (Rev.1), Agenda ID# 14852. May 26, 2016.

recommends that moving forward, SDG&E start with the illustrative rates adopted by Resolution E-4787[10]. These rates are shown in the "2016" column below. ORA then escalates these rates by its revenue allocation recommendations for the residential class to arrive at the illustrative rates shown in column "2017". The actual, final rates would be based on other factors such as potential revenue requirement and sales changes that are unknown at present. ORA also recommends that GRC rate changes be implemented simultaneously with SDG&E's rate reform implementation in 2017. That way, it will be easier to account for the changes that have occurred to the RAR over the past 12 months.

	SDG&E Proposal		ORA Recommendation	
SCHEDULE DR	**"Current"**	**2017**	E-4787	2017
Baseline Energy	0.190	0.236	0.190	0.201
101% to 130% of Baseline	0.217	0.236	0.190	0.201
131% to 400% of Baseline	0.418	0.394	0.391	0.414
Above 400% of Baseline	0.418	0.394	0.391	0.414
SCHEDULE DR -LI (CARE)				
Baseline Energy	0.162	0.229	0.114	0.121
101% to 130% of Baseline	0.186	0.229	0.114	0.121
131% to 400% of Baseline	0.264	0.386	0.245	0.259
Above 400% of Baseline	0.264	0.386	0.245	0.259

Moving forward, Resolution E-4787 orders SDG&E to file a supplement to AL 2861-E with revised tariff sheets reflecting the rates as outlined in the resolution.[11] Furthermore, the March 14 ruling of ALJ McKinney explicitly requires worksheets and sufficient workpapers for Energy Division staff and other parties to quickly determine if the proposed rate changes comply with the requirements of D.15-07-001.[12] This requirement should apply in this Application

[10] Page 8, far right column

[11] Order Number 3, page 13.

[12] R1206013 Email Ruling Setting Forth Requirements for Future Advice Letter Filings and

(continued on next page)

as well: it is critical that these workpapers include updates to all rates in SDG&E's consolidated model using the guidance set forth in Resolution E-4787, so that the effects, including bill impacts, can be studied and understood.

These required worksheets and workpapers should be made available to all intervenors as the basis for updates to its consolidated models for settlement discussions, bill impact studies, and as the starting point for other intervenors' rate design testimony in this case.

B. Tier Flattening Ratios are a Guideline, not a Requirement

The Commission should maintain its policy direction to cap tier 1 increases should continue to be at RAR+ 5%, according to its guidance in D.15-07-001 and Resolution E-4787. The Commission's other target for reaching a 1 to 1.25 tier ratio by 2019 is a worthy goal, but one that is of a lower priority than[13] the cap on Tier 1 rates. However, embedded in SDGE's Rate Design model are coded values[14] which strictly follow the Tier Differential Ratios established by the Decision.[15] The Commission has repeatedly clarified that the tier differential ratios discussed in the Decision are meant to act as a guideline, not a mandate.[16] "The statute does not require a set timeline[17]" for tier flattening, especially given the tension between keeping a subset of usage affordable for all households and price decreases for larger users. The Commission appropriately ruled[18] that the

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(continued from previous page)
Notifying Parties of Next PRRR Workshop and Other Procedural Matters. Sent Mon 3/14/2016 4:48 PM.

[13] Decision at 292 and 293.

[14] At tabs "Total Proposed Rate - Year 1", "Total Proposed Rate - Year 2", and "Total Proposed Rate - Year 3."

[15] D.15-07-001 at page 293.

[16] Per D.15-07-001, page 293.

[17] Decision, page 270.

[18] March 14, 2015 email Ruling of ALJ McKinney.

tier 1 rate cap needs to be applied first, and that reducing the differential between tier 1 and tier 2 rates continue.

C. TOU Periods Should Remain Fixed for Two GRC Cycles, but CPP Periods May Change Annually

In this application, SDG&E proposes to shorten its TOU peak period from seven hours to a shorter five-hour on-peak period with a stronger price signal,[19] expand its super off-peak hours,[20] and align its winter TOU periods with the proposed summer TOU periods. As discussed in detail in Chapter 1 of this testimony, ORA recommends that SDG&E's proposed super off-peak period not be adopted, and that the summer season be shortened to four months from July through October.

ORA agrees with SDG&E that TOU periods should be effective for a minimum of five years, consistent with Assembly Bill 327[21]. To promote regulatory efficiency, reduce rate changes, and simplify customer communications, ORA further recommends that when possible, TOU periods be re-examined during every other GRC cycle, rather than through a five-year Rate Design Window, so that changes to the underlying marginal costs can be examined at the same time.

While ORA does share some concern that customers introduced to Critical Peak Pricing ("CPP") for the first time would be confused by the asymmetry between SDG&E's proposed CPP period from 2—6 pm and the 4—9 pm TOU period, ORA also recognizes that CPP addresses different needs, and does not oppose SDG&E's proposal to change CPP event periods more frequently,[22]

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[19] Exhibit SDG&E-01. Prepared Direct Testimony of Cynthia Fang, CF-19, lines 10—12. February 9, 2016.

[20] CF-19.

[21] CF-23, lines 3—5.

[22] CS-23 at lines 4—5.

because CPP customers voluntarily opt into the program and receive far more notifications including a text, email, or phone call before each event.

Because SDG&E does not specify exactly how often CPP event-hours should be changed, ORA recommends that absent extenuating circumstances, CPP event-hours not be changed more than once per year, ideally aligned with the start of the summer season. Even though events can be called year-round, they are still more likely to be called during the summer, and communications about other rate changes could be leveraged.

V. CONCLUSION

ORA recommends that its proposed residential rates be adopted. These rates are based on ORA's proposed revenue allocation to the residential class, and follow the guidance on rate changes and restructuring from D.15-07-001 and Resolution E-4787.

CHAPTER 8

SMALL COMMERCIAL RATE DESIGN

NATHAN CHAU

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CHAPTER 8
SMALL COMMERCIAL RATE DESIGN
NATHAN CHAU

I. SUMMARY AND RECOMMENDATIONS

This chapter analyzes San Diego Gas & Electric ("SDG&E") rate design proposals for its 116,000 small commercial customers[1] and presents the Office of Ratepayer Advocates' ("ORA's") recommendations for SDG&E's General Rate Case ("GRC") Phase 2 proceeding.

In April 2016, SDG&E completed transitioning its small commercial customers to mandatory Time-of-Use rates ("TOU"), default Critical Peak Pricing ("CPP") rates. Customers who have been accustomed to flat seasonal rates for decades will now need to familiarize themselves with how their bills are impacted by ***when*** they use energy in addition to how much energy they use. This particular transition is part of the Commission's goal of moving customers to time varying rates, intending to align rates to system costs and integrate renewables.

In this proceeding, SDG&E is also proposing to overhaul the current TOU periods. Each of these changes would cause significant impacts on the majority of customers' bills. ORA proposes the following protections to ensure that small commercial customers have adequate time to adjust their operation due to electric rate changes and to mitigate adverse bill impacts.

In summary, ORA's recommendations are:

1. Reject SDG&E's proposed increases to fixed charges;
2. Propose the following transitional TOU rates with flatter on-peak to off-peak rate differentials;

[1] 116,103 customers in 2013

TOU-A-P[2]			
Basic Service Fee	Current	SDG&E	ORA
0-5 kW	$7.00	$14.00	$7.00
5-20 kW	$12.00	$24.00	$12.00
20-50 kW	$20.00	$40.00	$20.00
>50 kW	$50.00	$100.00	$50.00
RYU Adder	$1.17	$1.87	$1.03
Energy Charge			
Summer On-Peak	$0.26359	$0.32506	$0.32118
Summer Off-Peak[3]	$0.23490	$0.25083	$0.27277
Summer Super Off-Peak[4]	$0.20443	$0.18958	$0.22659
Winter On-Peak	$0.23006	$0.22504	$0.24412
Winter Semi-Peak	$0.21588	$0.21440	
Winter Super Off-Peak	$0.19623	$0.20390	$0.22391

TOU-A[5]			
Basic Service Fee	Current	SDG&E	ORA
0-5 kW	$7.00	$14.00	$7.00
5-20 kW	$12.00	$24.00	$12.00
20-50 kW	$20.00	$40.00	$20.00
>50 kW	$50.00	$100.00	$50.00
Energy Charge			
Summer On-Peak	$0.30218	$0.41095	$0.33867
Summer Off-Peak	$0.26717	$0.25083	$0.29367
Summer Super Off-Peak	$0.22570	$0.21362	$0.24867
Winter On-Peak	$0.23006	$0.22504	$0.24412
Winter Semi-Peak	$0.21588	$0.21440	
Winter Super Off-Peak	$0.19623	$0.20390	$0.22391

[2] TOU-A-P is the default TOU-CPP rate

[3] Currently designated as "Semi Peak"

[4] Currently designated as "Off-Peak." However, SDG&E's consolidated model uses the old designations.

[5] TOU-A is a traditional TOU rate without a CPP element. This is the rate the majority of customers opting out of TOU-A-P would likely opt in to.

3. Propose the following TOU configuration for schedules TOU-A-P and TOU-A.

TOU period	Summer	Winter
On-Peak	4 PM - 9 PM **Weekdays**	4 PM - 9 PM **Weekdays**
Off-Peak	6 AM - 4 PM, and 9 PM to Midnight, Summer **Weekdays**	N/A
Super Off-Peak	All other periods (*including weekends*)	All other periods (*including weekends*)
Seasonal Description	July through October	November through May

4. Retain many of the rate elements that currently exist on SDG&E's schedule A-TOU, and recommend that SDG&E rename this schedule.

II. SDG&E'S PROPOSALS

Movement towards "cost-based" rates is a commonality in all of SDG&E's rate design proposals. These proposed transitions and the subsequent changes warrant close attention to examining how customers' bills and reactions are impacted.

In its application, SDG&E proposes to:

1. Increase differentiation between on-peak and off-peak rates beginning in 2017;
2. Increase the customer charge by 100% over three years for the majority of its customers;
3. Implement a new "cost-based" rate option;
4. Re-open and revamp schedule A-TOU; and
5. Change TOU and CPP periods for all of its customers.

III. DISCUSSION

SDG&E's proposal could create significant customer confusion and backlash as a result of levying increased fixed charges at the same time when their rates are being completely restructured. This confusion could be exacerbated by the abrupt timing of implementing new TOU periods. Customers would have merely a few months' worth of experience on existing TOU periods only to have new TOU periods imposed on them.[6] Concern with both the scope and number of changes these customers will experience forms the basis for many of ORA's proposals in this chapter.

The Commission has stressed that "transitions to 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."[7] SDG&E's proposals largely ignore these principles.[8]

Time-Of-Use ("TOU") Rates

TOU pricing charges different prices for electricity depending on the timing of energy consumption. TOU rates attempt to group similar hourly energy prices into "blocks" for greater simplicity. The implementation of TOU rates is intended to motivate customers to "reduce their electricity use during times of peak electricity demand" when system energy costs are high.[9]

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[6] Assuming the new rates are implemented March 2017, the latest of wave of customers transitioned to mandatory TOU will only have 10 months' worth of experience on the current TOU periods.

[7] Rate Design Principle 10 adopted by CPUC, D.15-07.001, page 28

[8] Though SDG&E has proposed to implement rate design changes "in transitional phases," (CF-8), the movement to "cost-based" rates is too aggressive and does not recognize the scale of the changes that customers would already be experiencing.

[9] D-12.12.004, Findings of fact 2

The default small commercial rate structure is a traditional time of use pricing structure with a CPP overlay.[10] During non-CPP event periods, customers pay TOU-based electric retail prices. A surcharge is overlaid on the price that would have otherwise applied for every kilowatt-hour ("kWh") consumed during critical peak hours whenever a CPP event is called.[11] Such events are usually enacted for periods when wholesale market prices for providing electricity are high or when emergency conditions are anticipated. Since bill impacts resulting from CPP rates can be significant, these events are called on a day-ahead basis to give customers sufficient time to evaluate their energy usage and respond accordingly.

A. SDG&E's Proposal to Double Customer Fixed Charges Increases Bills For the Majority of Customers and is Inappropriate at this Time.

SDG&E proposes to double the customer charge for all kW demand levels by the end of a three year transition period,[12] so that rates are "more reflective of the manner in which costs are incurred."[13] ORA opposes any further increases to fixed customer charges for a number of reasons.[14]

1. Customers will need sufficient time to assess and make educated choices with regards to their rate options. Levying additional fixed charges should be avoided, as it will likely confuse some customers

[10] D-12.12.004, OP 4. The original implementation date for default CPP was November of 2014. This date was later extended to November 2015 via SDG&E's letter request to the Commission's Executive Director and subsequent advice letter, which was granted. See Page 4 of D.14.12.036.

[11] Used interchangeably with event periods.

[12] SDG&E-02-Swartz, CS-23

[13] SDG&E-02-Swartz, CS 21 "the MSF for all customer classes is well below cost-based levels." Clearly, due to the varying methodologies of calculating marginal customer access costs, and whether or not is even appropriate to include all costs associated with MCAC in a customer fixed charge is still up for debate.

[14] The viability of a fixed charge and what should go in it will be fully vetted in PG&E's upcoming GRC phase 2 proceeding.

as to why their bills are increasing and how they can respond. During this transition time, customers should be able to focus on understanding and responding to all the changes in their rates.

2. Customers will already be experiencing both rate increases[15] and TOU period changes in a very short time period.[16]
3. Customers have less control over their monthly bills when a larger fraction of it is unavoidable.
4. Customers are rewarded less for conserving the same amount of energy.
5. For many customers, increased fixed charges trade bill "stability" for significantly higher bills—an unlikely choice for most customers.

Customers may perceive increases to fixed charges as bill increases for no additional services rendered. The majority of smaller users among SDG&E's commercial customers would have a larger portion of their bill consist of unavoidable fixed charges. Customers with maximum annual demands falling below 5kW[17] who consume less than 932.63 kW a month, will experience monthly bill increases **attributable solely**[18] **to this increased fixed charge**, not taking into account other sources of bill increases attributed to other rate design elements such as TOU periods and rate differentials.

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[15] Under SDG&E's proposals, average small commercial rates will increase by 7.96%. Under ORA's proposals, the change in the small commercial average rate is 3.92%. See revenue allocation chapter for more information.

[16] Pursuant to PU code section 745, the commission should strive for TOU rates with TOU periods that are appropriate for 5 years. If new TOU periods were to be implemented March 2017, these customers will have only had between 10-14 months of experience on the current TOU periods.

[17] Roughly 54% of all customers fall within this distinction.

[18] This threshold is calculated by locating point at which the increase to the monthly service fee of 7 dollars is offset by a decrease of the same magnitude ($7) in the volumetric charges. The portion of distribution costs not recovered by the MSF, is allocated on an equal cents per kWh basis.

SDG&E's desire for increasing fixed customer charges needs to be tempered by customer impact considerations.[19] SDG&E's proposal would result in bill increases of more than 12% for 42.6% for all small commercial customers.[20] These same customers are already going to see rate increases and TOU period changes. On the other hand, keeping the fixed charges the same as they are now with all else being equal,[21] this number is only 9.7%[22] on an annual monthly average basis.

SDG&E states that its proposal will result in greater bill stability, but this would not help the majority of small commercial customers who would experience bill increases. There are better and more direct ways to promote bill stability, one of which is the level payment plan ("LPP"). Under a LPP, customers pay about the same amount on their bills each month based on projected usage. This amount may be adjusted once every three months, as actual energy use is factored into a rolling 12-month average.[23] SDG&E should market this option should to customers who may stand to benefit the most from increased bill stability.

B. Customers Who Cannot Shift Energy Usage Will Experience TOU and CPP-related Adverse Bill Impacts

ORA is concerned with managing adverse bill impacts that can result from a TOU-CPP rate. These issues are especially concerning for customers who do not understand how their usage interacts with these restructured rates. Additionally, customers who cannot shift energy usage without compromising business operations will experience hardship associated with adverse bill impacts in the short run. This is of particular concern for seasonal businesses and businesses that

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[19] Rate design principle 10.

[20] Response to ORA-SDG&E DR 15, Question 1B, assumes 9 CPP events

[21] SDG&E's proposed rate including their marginal costs without the fixed charge increase (i.e. what SDG&E's proposal would look like if fixed charges were kept the same).

[22] Response to ORA-SDG&E DR 15, Question 1C, assumes 9 CPP events

[23] http://www.sdge.com/customer-service/level-pay-plan

primarily operate during on-peak periods.[24] Higher rates may squeeze profit margins, especially if these higher rates coincide with the times when it is most profitable to operate. Others, based on the nature of their work, cannot afford to curtail load at any time.[25]

It is imperative to mitigate impacts to these customers as they adjust to the new TOU rate structure without being unreasonably penalized simply for having suboptimal load shapes. More focus should be placed on ensuring that the transition to new TOU periods is as painless as possible and less on making sure that rates match SDG&E's assertions of what would be most "cost-based." Therefore, ORA modifies SDG&E's proposals in order to minimize rate shock and achieve wider customer acceptance.

1. ORA's TOU Period Proposal for Schedules A-TOU-P and TOU-A

The TOU periods that ORA is proposing for these schedules aim to preserve as much of the configuration of those currently in effect in order to ensure that the transition to the new rates is as smooth as possible. ORA's configuration retains the single super-off peak period on weekends that these customers currently face, and emulates SDG&E's TOU period proposal for the summer weekdays. However, ORA is proposing two periods for winter weekdays compared to SDG&E's three periods, given that the average marginal generation costs for the off-peak and super off-peak periods are too close to convey any meaningful price signals.[26] SDG&E currently bills customers based on a three period summer weekday. Retention of this three period summer weekday will alleviate customer confusion when the peak period shifts to later in the day. Both

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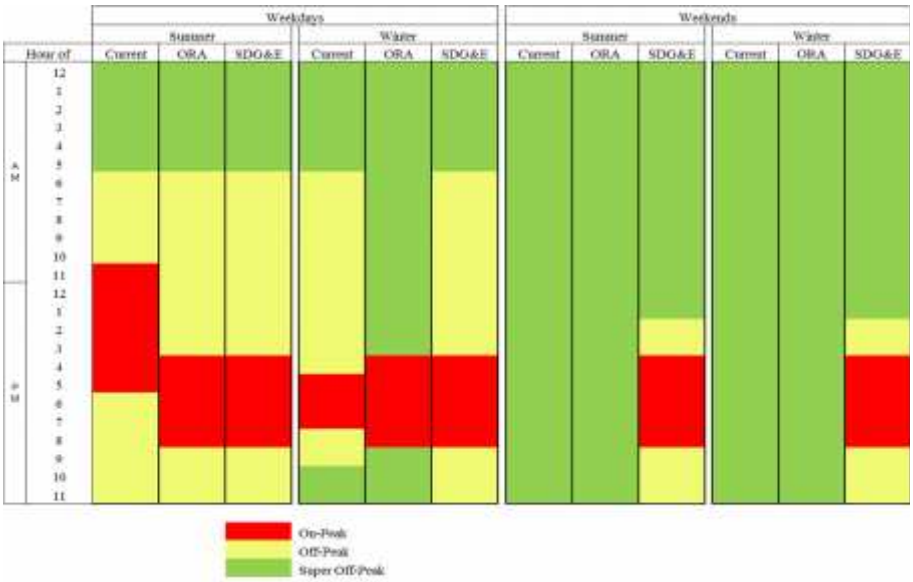
[24] Both SDG&E and ORA is proposing 4-9 pm on weekdays for the on-peak period. For example, restaurants and gyms would have difficulty shifting their energy usage away from 4-9 pm.

[25] For example, health clinics

[26] Please refer to marginal generation costs chapter.

the summer and winter on-peak periods proposed here, are consistent with ORA's proposed TOU periods that are inputs to ORA's proposed revenue allocation for this GRC Phase 2. While the on-peak period will most likely remain stable going forward, all other periods may require revision as system conditions change. Because these customers will experience fundamental changes to how they are billed within a time period that is unprecedentedly short, retaining as much stability as possible is important to mitigate unnecessary bill increases and rate shock. Below is a graphical representation of the TOU periods that customers currently see, and those they would see under SDG&E's and ORA's proposals.

Figure 8-1 TOU Period Comparison: Current, ORA, SDG&E



Under ORA's proposed TOU period configuration, the only major change that customers will see is the movement of the peak summer period to later in the day. This is reasonable given that TOU periods are intended to remain in place for a number of years to provide stability[27].

[27] PU Code Section 745 C 3. "The Commission shall strive for time-of-use rate schedules that utilize time periods that are appropriate for at least five following years."

2. A Milder TOU-CPP Will Reduce Bill and Price Fluctuations and Allow Customers Time to Adjust to a Myriad of Changes

Imposing highly differentiated time variant pricing prematurely can create hardship for vulnerable small businesses just when they are starting to learn how to respond to these price signals, and when they are also learning about new TOU periods. Therefore, ORA recommends that a milder TOU-CPP rate be adopted in order to ease customers into time-differentiated rates, avoid rate shock, and achieve wider acceptance and understanding. This "CPP-Lite" rate will reduce customer complaints and mitigate bill fluctuations, especially in light of the fact that these customers will undergo the additional disruption of new TOU periods.

ORA proposes to

1. Reduce CPP surcharge from $1.87 to $1.03 and
2. Flatten Summer TOU rates.

ORA's recommendation of a lower marginal capacity value and different relative loss of load probability ("LOLP") figures results in the reduction in the CPP surcharge from $1.87 to $.98.[28] ORA allocates 58% of assigned capacity costs to on-peak periods to this CPP adder, the same manner by which SDG&E determines the size of its CPP adder. ORA reduces the summer rate differentials by fixing the super-off peak period commodity rate equal to the revenue neutral commodity super-off peak rate and enforcing a moderate ratio of 1.35 between the commodity on-peak and off-peak rates.[29] Overall, the final rate differential between summer on-peak and super-off peak is about 1.40:1 when all the other rate components are blended with these commodity rates. Currently, customers see a very moderate ratio of 1.27:1.[30] ORA's proposal is reasonable since both

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[28] For more information on marginal generation capacity costs and LOLP, see chapter 2.

[29] See SDG&E's "Consolidated Model GRC P2" submitted with its February filing, Commodity Transition Path tab, cells BA123/BA124

[30] Tariff sheet EECC-A-TOU-P (AL 2780.E): Summer on-peak commodity rate =$ .10865 and summer off-peak (equivalent to super off peak in this proceeding) commodity rate =$ .05989

(continued on next page)

Southern California Edison's ("SCE") and Pacific Gas and Electric's ("PG&E") small commercial customers, despite having more time and experience on mandatory TOU rates, still see very moderately differentiated TOU rates.[31] The on- to off-peak[32] price ratio for PG&E's A-1 schedule is 1.25:1 and its equivalent CPP charge amounts to $.60.[33] Similarly, the on- to off-peak[34] price ratio for SCE's schedule TOU-GS-1 CPP option is 1.41:1 with a CPP charge of $1.37.[35] On the other hand, SDG&E proposes a ratio of 1.71:1.[36] Below is a table that illustrates the difference in the distribution of bill impacts on average monthly bills that would result under ORA's and SDG&E's proposals for schedule TOU-A-P assuming no change in the way the manner by which customers use energy.

(continued from previous page)
Tariff sheet TOU-A (AL 2840-E) $.12285 for all periods

Final rate differential = (.10865+.12285)/(.05989+.12285)=1.27

[32] PG&E's equivalent of SDG&E's super off-peak designation.

[33] PG&E A-1 TOU rates effective March 1, 2016. On Peak charge $.25806, Off-peak charge $.20705.

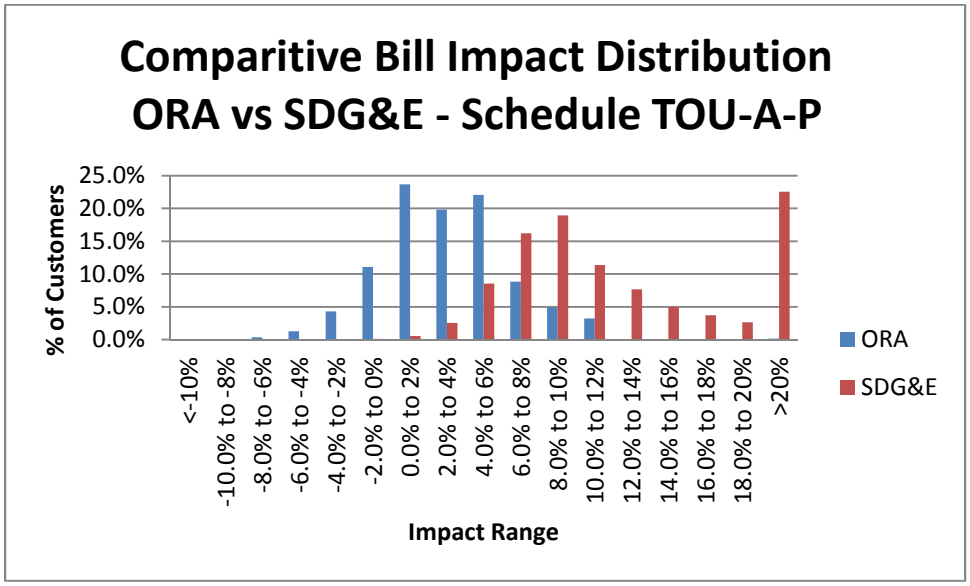
[34] SCE's equivalent of SDG&E's super off-peak designation.

[35] SCE TOU-GS-1 CPP Option Rate effective Jan 1, 2016 Option On Peak Charge $.19327, Off-Peak Charge $.13712.

[36] See SDG&E's "Consolidated Model GRC P2" submitted with its February filing.

(Tab "Total Proposed Rate - Year 3" : cells AA1290 + AC1290 + AG1290, + tab "DPP_CPP-D - Year 3"J1290)/(Tab "Proposed Rate - Year 3": cells AA1296 + AC1296 + AG1296, + tab DPP_CPP-D - Year 3," cell J1296)

Figure 8-2 Comparative Bill Impact Distribution[37]



Generally, ORA's illustrative rates result in much milder bill impacts, with only 3.5% of customers projected to see bill increases above 10% while a staggering 53% of customers will see increases over 10% under SDG&E's proposal. ORA's proposal appropriately minimizes customer bill impacts, thus allowing customers with varying levels of engagement and awareness time to assess what the new TOU periods mean to their operations.

ORA recommends that the price differentials for schedule A-TOU also be moderated so that the customers who prefer the predictability associated with A-TOU, a traditional TOU rate without a dynamic pricing element, are not unduly penalized for opting out of the default CPP rate. Although it is too soon to tell just how many customers will opt out of CPP, this number might be significant. In

[37] For ORA's bill impacts, see SDG&E's response to DR 17 of new filing, Question 2. For SDG&E's bill impacts, see SDG&E's response to DR 15, Question 1B. **The impacts resulting from ORA's proposed rate are most likely a little higher overall than those illustrated in the histogram chart above for the reason that ORA asked SDG&E to conduct bill impacts for illustrative rates that are lower than those proposed in this chapter. Much of the savings associated with ORA's rate is attributed the differences between ORA's and SDG&E's position on fixed charges, class revenue allocation, and the fact that ORA's summer period consists of 4 and not 6 summer months**.

fact, CPP has proved to be unpopular for the large commercial customers who, prior to default CPP, had years of experience on TOU rates. In SCE's territory, two years after the inception of default CPP, the retention rate of SCE's non-legacy large accounts on CPP rates was only 33%.[38] ORA proposes setting the on- to super-off peak price differential to 1.37, compared to SDG&E's proposed 1.92, by imposing a differential of 4.5 cents between the on- and off-peak and between the off- and super off-peak commodity rates.

The changes that these customers will undergo are unprecedented. TOU periods have not changed in decades, but under SDG&E's proposal these customers will be subjected to two different sets of TOU periods in roughly 14 months. Now is not the time to impose highly differentiated rates on customers, as customers need to first understand, accept and engage with the newly changed rates before being expected to respond to even steeper price differentials. Moreover, bill protection for customers on TOU-A-P will expire by April 2017 for the customers who most recently transitioned and even earlier for those who transitioned in November 2015.[39]

3. SDG&E's Proposal to Funnel CPP Under Collection through a Balancing Account is Inappropriate

SDG&E's proposal to recover CPP revenue under-collection from all classes should be rejected. SDG&E argues that because more customers will participate in CPP rates than in the past, the manner in which CPP under collection is currently dealt with must change.[40] SDG&E errs in this statement because CPP

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[38] A.11-06-007 CLECA to SCE Q3.7. "67% of legacy accounts remain on CPP whereas only 33% of non-legacy accounts remain on CPP as of October 3, 2011. The retention rate is determined as of inception of the default program on October 1, 2009." **See attachment A.**

[39] Customers were transitioned to mandatory TOU in waves. Customers receive only one year of bill protection if they are on a CPP rate.

[40] SDG&E-02-Swartz, CS-55

rates are not equally prevalent in all classes. The number of residential customers on CPP rates is very small as CPP is not their default rate. It would be unfair to subject residential customers to the costs for which they are not responsible by any significant measure. SDG&E should therefore maintain its current policy of reallocating under collection back to the class from which under collection originates.[41]

C. SDG&E's New Schedule Options

1. A-TOU Should Retain its Current Rate Structure.

SDG&E requests to reopen and revamp legacy rate A-TOU, a rate that is accessible to customers whose maximum annual demand ranges between 20 kW and 40 kW. SDG&E proposes to escalate the monthly service fee from $19.12/customer-month to $62.83/customer-month for customers of all sizes and introduce a demand charge that ratchets up from $0/kW to $4.91/kW annually over three years[42].

[41] See consolidated models, Under collection amount spread back to all customers in ML Industrial customers.

[42] SDG&E-02-Swartz, CS-45

Table 8-1 Comparison present and proposed A-TOU rates

SCHEDULE A-TOU		
	Present	SDG&E Year 3
Basic Service Fee		
0-5 kW	$19.12	$62.83
5-20 kW	$19.12	$62.83
20-50 kW	$19.12	$62.83
>50 kW	$19.12	$62.83
Non-Coincident Demand	$0.00	$4.91
Energy Charge		
Summer		
On-Peak	$0.4608	$0.3723
Off-Peak	$0.2756	$0.2016
Super Off-Peak	$0.2524	$0.1510
Winter		
On-Peak	$0.2245	$0.1753
Off-Peak	$0.2109	$0.1646
Super Off-Peak	$0.1921	$0.1540

ORA does not oppose SDG&E's proposal to re-open this rate. However, ORA recommends retaining the current structural elements of this rate as much as possible. Monthly fixed charge should remain at $19.12/ customer-month. Further, demand charges are not appropriate at this time for the same reasons that ORA is proposing to flatten the summer rate differentials. The priority now is the have customers adapt to the new TOU periods.

Finally, ORA recommends that SDG&E rename this schedule so that it is more easily distinguishable by customers. "A-TOU" is too similar to schedule "TOU-A." This will avoid confusion in customer enrollments and reduce customer complaints.

2. SDG&E's Should Track the Amount of Revenue Under-Collection for its New Cost-Based Option.

SDG&E proposes to offer a full "cost-based rate" that "consists of a larger fixed charge and a reduced volumetric rate" as an option for customers seeking

greater bill stability.[43] Though this rate would be open to all customers, including those with maximum annual demands less than 20 kW, large customers are the ones that most likely stand to benefit from this rate owing to that fact that this rate features much higher monthly fixed charges. Since ORA anticipates that the number of customers who would opt in to this rate is likely to be small, ORA does not take issue with this proposal. However, SDG&E should track the amount of revenue under-collection that would result from this rate separately from that which will result from the re-opening of A-TOU. Finally, consistent with ORA's recommendations of renaming schedule A-TOU, SDG&E should develop a unique name for this schedule.

III. CONCLUSION

SDG&E's small commercial customers will experience many disruptive changes over a very short period of time. In order to reduce these customers' bill impacts and give them time to adjust to multiple rate changes, the Commission should adopt ORA's proposals.

[43] SDG&E-02-Swartz CS-45

ATTACHMENT A

DATA REQUEST CLECA-SCE A.11-06-007

Southern California Edison
2012 GRC Phase 2

DATA REQUEST SET CLECA-SCE-GRC PHASE 2-BRB-003

To: CLECA
Prepared by: Janine Nelson-Hoffman
Title: CPP Project Manager
Dated: 09/30/2011

Question Q.03.7:

3.7. What is the retention rate for CPP customers as of September 30, 2011 for both legacy and non-legacy CPP customers?

Response to Question Q.03.7:

As of October 3, 2011, the retention rate for Critical Peak Pricing (CPP) is 41%. Of the legacy accounts, 67% remain on CPP, whereas 33% of nonlegacy accounts remain on CPP. The retention rate is determined as of inception of the default program on October 1, 2009.

QUALIFICATIONS OF

NATHAN CHAU

Q.1. Please state your name and business address.

A.1. My name is Nathan Chau. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Office of Ratepayer Advocates ("ORA"), Electricity Planning and Policy Branch.

Q.3. Please describe your educational and professional experience

A.2. I hold a Bachelor of Science degree in Applied Economics from the University of the Pacific. My degree included coursework in finance, economics, and econometrics that I find relevant to this case. I joined the Commission in April 2015 and have since been involved in SDG&E's GRC Phase 2, the Time-of-Use Order Instituting Rulemaking, and the Residential Rate Reform proceeding.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapters 1 and 8 of ORA's prepared testimony, on Marginal Customer Access Costs and Small Commercial Rate Design respectively.

QUALIFICATIONS OF

LOUIS IRWIN

Q.1. Please state your name and business address.

A.1. My name is Louis Irwin. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Regulatory Analyst in the Office of Ratepayers Advocates.

Q.3. Please describe your educational and professional experience.

A.3. I have a Master of Arts in Economics from the University of Colorado at Boulder with a focus on environmental, energy and urban issues and a Master of Public Administration from the JFK School of Government in Cambridge, Massachusetts. My thesis, at C.U. Boulder, focused on natural resource scarcity and pricing. Both degrees included coursework in finance and economics that I find relevant to this case. I also have a Bachelor of Arts in Psychology from U.C. Berkeley with a focus on organizational and business psychology applications. While at the U.C. Berkeley University Students Cooperative Association, I held four elected, paid positions including being on the Judicial Board, the General Board (which decided such matters as whether or not to buy additional property) and the Capital Improvements Committee. Since joining DRA in 1999, I have worked on a variety of energy related issues ranging from distributed generation to cost of capital cases. More recently, I have worked on marginal cost and revenue allocation aspects of general rate cases. Prior to coming to the Commission, I worked for seven years in economic consulting, regarding socio-economic impacts due to mining and energy facilities, including the proposed high-level nuclear waste site at Yucca Mountain, Nevada. My more recent consulting experience was directly in the energy field, performing productivity and comparative electric rate analyses with Christensen Associates, a specialist in these areas.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring testimony on marginal distribution demand cost issues (Chapter 2).

QUALIFICATIONS OF
BENJAMIN GUTIERREZ

Q.1. Please state your name and business address.

A.1. My name is Benjamin Gutierrez. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed as a Public Utilities Regulatory Analyst in the Office of Ratepayer Advocate's (ORA's) Electricity Pricing and Customer Programs branch.

Q.3. Please describe your educational and professional experience.

A.3. I have a Bachelor of Arts in Environmental Science and Public Policy from Harvard University. For nearly two years, I worked as a Clean Energy Coordinator and Philanthropy Coordinator for the Malaysian nonprofit organization Land Empowerment Animals People (LEAP), where I contributed research and writing to a report that compared the costs and resource availabilities of renewable energy and fossil fuel technology options in the Malaysian state of Sabah. I joined the Office of Ratepayer Advocates in 2015, and I have been involved in SDG&E's GRC Phase 2, the Residential Rate Reform OIR proceeding's residential Time-Of-Use (TOU) pilots and the Time-Of-Use OIR proceeding.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 3 of ORA's testimony on marginal generation capacity costs.

QUALIFICATIONS OF
ROBERT M. FAGAN (SYNAPSE ENERGY ECONOMICS, INC.)

Q.1. Please state your name and business address.

A.1. My name is Robert M. Fagan. My business address is 485 Massachusetts Ave., Cambridge, MA 02139.

Q.2. By whom are you employed and in what capacity?

A.2. I am a Principal Associate with Synapse Energy Economics, Inc. I have been employed in that position since 2005.

Q.3. Please describe your educational and professional experience.

A.3. I am a mechanical engineer and energy economics analyst, and I have examined energy industry issues for more than 25 years. My activities focus on many aspects of the electric power industry, especially economic and technical analysis of electric supply and delivery systems, wholesale and retail electricity provision, energy and capacity market structures, renewable resource alternatives including on-shore and off-shore wind and solar PV, and assessment and implementation of energy efficiency and demand response alternatives.

I hold an MA from Boston University in Energy and Environmental Studies and a BS from Clarkson University in Mechanical Engineering. I have completed additional course work in wind integration, solar engineering, regulatory and legal aspects of electric power systems, building controls, cogeneration, lighting design and mechanical and aerospace engineering.

I submitted pre-filed modeling rebuttal testimony in October 2014 in Docket R.12-06-013 (jointly, with Patrick Luckow). I submitted pre-filed modeling testimony in August 2014 in the 2014 LTPP docket (R.13-12-010; jointly, with Patrick Luckow). I also testified in Track 1 and Track 4 of the R.12-03-014 proceeding, and in the A.11-05-023, Application of San Diego Gas & Electric Company ((U902E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Energy Center. I also submitted joint testimony with Patrick Luckow in the PG&E 2015 Rate Design Window case (A.14-11-014), the SCE GRC2 case (A.14-06-014), and the SDG&E RDW case (A.14-01-027). I have been involved in California

renewable energy integration and related resource adequacy issues as a consultant to the ORA since the late fall of 2010. I have also testified in numerous state and provincial jurisdictions, and the Federal Energy Regulatory Commission (FERC), on various aspects of the electric power industry including renewable resource integration, transmission system planning, resource need, and the effects of demand-side resources on the electric power system.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am testifying on behalf of the California Public Utilities Commission's Office of Ratepayer Advocates (ORA) and sponsoring Chapter 4 of ORA's testimony on Marginal Generation Cost.

QUALIFCATIONS OF

PATRICK LUCKOW (SYNAPSE ENERGY ECONOMICS, INC.)

Q.1. Please state your name and business address.

A.1. My name is Patrick Luckow. My business address is 485 Massachusetts Ave., Cambridge, MA 02139.

Q.2. By whom are you employed and in what capacity?

A.2. I am an Associate with Synapse Energy Economics, Inc. I have been employed in that position since I started work at Synapse in 2012.

Q.3. Please describe your educational and professional experience.

A.3. I am an Associate at Synapse, with a special focus on calibrating, running, and modifying industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives.

Prior to joining Synapse, I worked as a scientist at the Joint Global Change Research Institute in College Park, Maryland. In this position, I evaluated the long-term implications of potential climate policies, both internationally and in the U.S., across a range of energy and electricity models. This work included leading a team studying global wind energy resources and their interaction in the Institute's integrated assessment model, and modeling large-scale biomass use in the global energy system.

I hold a Bachelor of Science degree in Mechanical Engineering from Northwestern University, and a Master of Science degree in Mechanical Engineering from the University of Maryland.

I submitted pre-filed modeling rebuttal testimony in October 2014 in Docket R.12-06-013 (jointly, with Robert Fagan). I submitted pre-filed modeling testimony (jointly, with Robert Fagan) in August 2014 in the 2014 LTPP docket (R.13-12-010). I also submitted joint testimony with Bob Fagan in the PG&E 2015 Rate Design Window case (A.14-11-014), the SCE GRC2 case (A.14-06-014), and the SDG&E RDW case (A.14-01-027).

Q.4. What is your area of responsibility in this proceeding?

A.4. I am testifying on behalf of the California Public Utilities Commission's Office of Ratepayer Advocates (ORA) and sponsoring Chapter 4 of ORA's testimony on Marginal Generation Cost.

QUALIFICATIONS OF
ERIC DURAN

Q.1. Please state your name and business address.

A.1. My name is Eric Duran. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Office of Ratepayer Advocates, Electricity Planning and Policy Branch.

Q.3. Please describe your educational and professional experience.

A.3. I received a Master of Science Degree in Agricultural and Resource Economics from the University of California, Davis in 2013. I received a Bachelor of Science Degree in Environmental Science with a concentration in Economics from the University of California, Riverside in 2011. I have been employed by the Office of Ratepayer Advocates since November 2013. I have sponsored testimony before the Commission in the past concerning sales forecasts and rate design for water utilities.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 5 of ORA's testimony, which presents ORA's analysis and recommendations for SDG&E's sales forecasts.

QUALIFICATIONS OF

AARON LU

Q.1. Please state your name and business address.

A.1. My name is Aaron Lu. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst V in the Office of Ratepayer Advocates ("ORA"), Electricity Planning and Policy Branch.

Q.3. Please describe your educational and professional experience.

A.3. I received dual Bachelor of Science Degrees in Environmental Science and Neuroscience from the University of California, San Diego. I also possess a Master of Environmental Management in Energy from the Nicholas School of the Environment at Duke University. I joined the Commission in June 2013 in Energy Division's Energy Efficiency Branch and transferred to ORA's Electricity Planning and Policy Branch in November 2015. At present, I am involved in SDG&E's General Rate Case Phase II, the Time-of-Use Order Instituting Rulemaking, and the Residential Rate Reform proceeding.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 6 of ORA's testimony, which presents ORA's policy Revenue Allocation.

QUALIFICATIONS OF

CHERIE CHAN

Q.1. Please state your name and business address.

A.1. My name is Cherie Chan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By whom are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Office of Ratepayer Advocates.

Q.3. Please describe your educational background and professional experience.

A.3. I hold a Bachelor of Arts degree from the University of California at Berkeley, with a major in Social Welfare and minors in Business and Demography. I have worked as a Billing Analyst at PG&E and as Manager of the Billing Department at Utility.com. At ABB Inc., I helped implement Interval Data Software products for utilities as a Project Manager and Product Engineer. I joined the Commission in 2005 and have sponsored Marginal Cost, Rate Design and Advanced Metering Infrastructure testimony, departing in 2007 to manage marketing and product management of smart grid programs at eMeter and Oracle. I returned to the Commission in 2009 and have continued to testify in rate design and other proceedings.

Q.4. What testimony are you sponsoring in this proceeding?

A.4. I am sponsoring Chapter 7, Residential Rate Design Policy.