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

Application: 15-04-012
Exhibit No.: SDG&E-06

PREPARED DIRECT TESTIMONY OF

WILLIAM G. SAXE

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN

SUPPORT OF SECOND AMENDED APPLICATION

CHAPTER 6

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

February 9, 2016

#301914

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CHAPTER 6

I. OVERVIEW AND PURPOSE

The purpose of my direct testimony is to present San Diego Gas & Electric Company's ("SDG&E") updated marginal distribution demand and customer costs, and the resulting electric allocation of distribution revenues to customer classes based on these marginal distribution costs.

My testimony is organized as follows:

- **Section II – Background**: describes the development of the proposed marginal distribution demand and customer costs, and the use of these marginal costs to develop the proposed electric distribution revenue allocation;
- **Section III – Marginal Distribution Demand Costs**: presents the development of the proposed updated marginal distribution demand costs based on the National Economic Research Associates ("NERA") Regression Method;
- **Section IV – Marginal Distribution Customer Costs**: presents the development of the proposed updated marginal distribution customer costs based on the Rental Method;
- **Section V – Distribution Revenue Allocation**: presents the proposal to use the updated marginal costs coupled with the Equal Percent of Marginal Costs ("EPMC") method to allocate the authorized distribution revenue requirement;
- **Section VI – Summary and Conclusion**: provides a summary of recommendations; and
- **Section VII – Statement of Qualifications**: presents my qualifications.

My testimony also contains the following:

- **Appendix – Glossary of Acronyms;**
- **Attachment A – Marginal Distribution Costs;**
- **Attachment B – Distribution Revenue Allocation;**
- **Attachment C – Customer Service Distribution Cost Allocation;**
- **Attachment D – Revisions to 2016 Marginal Distribution Customer Costs and Distribution Revenue Allocation; and**
- **Attachment E - Illustrative New Customer Only ("NCO") Marginal Distribution Customer Costs.**

II. BACKGROUND

For more than 30 years, the California Public Utilities Commission ("Commission") has relied on marginal costs as the basis for revenue allocation and rate design development for the different customer classes. My testimony presents SDG&E's updated studies for both marginal distribution demand and customer costs. The marginal distribution demand costs are based on the NERA Regression Method while the marginal distribution customer costs utilize the Rental Method. Because recent SDG&E rate design proceedings, specifically its Test Year ("TY") 2008 and TY 2012 General Rate Case ("GRC") Phase 2 proceedings (Application ("A.") 07-01-047 and A.11-10-002, respectively), were decided by settlement on revenue allocation, there was no formal adoption of marginal costs or marginal cost methodology in those proceedings.

Marginal cost is the change in costs caused by providing one additional unit of a good or service. In the electric utility context, marginal cost is defined as the change in costs to provide electric service to customers. Marginal distribution demand costs measure the cost of serving an additional unit of customer kilowatt ("kW") demand on the electric distribution grid while marginal distribution customer costs reflect the cost of adding an additional customer to the electric distribution grid. These marginal distribution costs are used as a reference for the determination of cost-based rates when SDG&E designs distribution rates to reflect the costs of providing utility service.

SDG&E is proposing that the updated marginal distribution costs proposed in this TY 2016 GRC Phase 2 Application provide the basis for the updated allocation of authorized distribution revenue requirements to customer classes.

III. MARGINAL DISTRIBUTION DEMAND COSTS

A. Marginal Distribution Demand Cost Background

Marginal distribution demand costs represent the cost of providing facilities from the high side of the substation to the final line transformer in order to meet the customer's individual demands. These marginal distribution demand costs are separated into feeder and local distribution components and substation components for the purposes of this GRC Phase 2 Application.

The development of marginal distribution demand costs focuses solely on distribution costs related to load growth. Therefore these marginal distribution demand costs do not include distribution costs related to reliability investments, replacement costs, or customer access costs, because these costs are not considered load growth-related.

The distribution demand cost component is derived in units of dollars-per-kW. To more accurately reflect the true investment cost, the costs are adjusted by various loading factors. These loading factors reflect additional costs that are necessary to meet the needs related to the addition of capacity to the distribution grid. Loading factors have been derived for Operations &

Maintenance ("O&M"), Administrative & General ("A&G"), General Plant ("GP"), and Working Capital ("WC").

B. Marginal Feeder and Local Distribution Cost

Marginal feeder and local distribution costs represent the cost of expanding facilities from the distribution substation to the point of customer access to serve an additional kW of demand. The cost of feeder and local distribution facilities is based on the projected investments needed to meet load growth on the SDG&E distribution grid during a specific planning horizon. These facilities include poles, fixtures, capacitors, and overhead and underground conductors and devices.

SDG&E will continue the use of the NERA Regression Method to calculate marginal feeder and local distribution costs. By definition, the NERA Regression Method uses ten years of historical and five years of forecasted feeder and local distribution investments along with annual distribution system peak loads in a regression methodology. The NERA Regression Method identifies the utility's cumulative incremental changes in distribution system peak loads as the independent variable, the utility's cumulative incremental distribution growth-related investments as the dependent variable, and then regresses the data over a fifteen-year period of data points, years 2002-2016 in this proceeding.

The feeder and local distribution investments used in the NERA Regression Method were obtained from distribution capital budget forecasts for the period 2014 through 2016.[1] Only three years of forecasted data was available from the capital budget data. Since only three years of forecast data was available, twelve years of historical investment data from years 2002 through 2013 was used to get fifteen years of data points for the NERA Regression Method.

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[1] 2014-2016 Distribution Capital Budget Forecasts are found in the SDG&E TY 2016 GRC Phase 1 (A.14-11-003), Direct Testimony of John D. Jenkins, Exhibit SDG&E-09, Appendix A.

Because marginal feeder and local distribution costs reflect the cost to meet new demand on the distribution grid, only capital budget investments and historical investments related to capacity additions were used in the regression calculation.

After obtaining the feeder and local distribution investment using the NERA Regression Method, the result is then adjusted to reflect both GP and WC loaders. The resulting amount (reflected in $/kW) is then annualized to $/kW-year using a Real Economic Carrying Charge ("RECC") factor derived for feeder and local distribution plant accounts. The annualized investment amount then receives an A&G plant loader, fixed O&M loader, and A&G fixed O&M loader. Lastly, the resulting loaded annualized investment sum is escalated to 2016 dollars to derive the marginal distribution demand costs for feeder and local distribution.[2]

SDG&E's marginal distribution demand costs for feeder and local distribution are provided in Attachment A.

C. Marginal Substation Costs

Marginal substation costs represent the forecasted cost for construction of substations to serve an additional kW of demand. The cost of substations is based on the projected investments needed to meet the load growth on the SDG&E distribution grid during a given period of time.

SDG&E will continue the use of the NERA Regression Method to calculate marginal substation costs. Again, by definition the NERA Regression Method uses ten years of historical and five years of forecast substation investments along with annual distribution system peak loads. The NERA Regression Method identifies the utility's cumulative incremental changes in distribution system peak loads as the independent variable, the utility's cumulative incremental

[2] 2016 escalations are the cost escalation factors presented in SDG&E TY 2016 GRC Phase 1 (A.14-11-003), Direct Testimony of Scott R. Wilder, Exhibit SDG&E-33, Workpapers.

distribution growth-related substation investments as the dependent variable, and then regresses the data over a fifteen-year period of data points, years 2002-2016 in this proceeding.

The substation investments used to calculate marginal substation costs were obtained from capital budget forecasts for the period 2014 through 2016.[3] Only three years of forecasted substation data was available from the capital budget data. Because only three years of forecast data was available, twelve years of historical investment data from years 2002 through 2013 was used to get fifteen years of data points for the NERA Regression Method. Because these marginal costs reflect the incremental substation costs needed to meet new demand on the distribution grid, only capital budget investments and historical investments related to capacity additions were used in the regression calculation. After obtaining the substation investment using the NERA Regression Method, the result is then adjusted to reflect both GP and WC loaders. The resulting amount (reflected in $/kW) is then annualized to $/kW-year using a RECC factor derived for substation plant accounts. The annualized investment then receives an A&G plant loader, fixed O&M loader, and A&G fixed O&M loader. Lastly, the resulting loaded annualized investment sum is escalated to 2016 dollars to derive the marginal distribution demand costs for substations.

SDG&E's marginal distribution costs for substations are provided in Attachment A.

IV. MARGINAL DISTRIBUTION CUSTOMER COSTS

A. Marginal Distribution Customer Cost Background

Marginal distribution customer costs represent the cost of providing an individual customer access to electrical service. These marginal costs are composed of two types of costs. The first is the cost associated with the investment required to provide access (hook up) to a new

[3] 2014-2016 Distribution Capital Budget Forecasts presented in the SDG&E TY 2016 GRC Phase 1 (A.14-11-003), Direct Testimony of John D. Jenkins, Exhibit SDG&E-09, Appendix A.

customer. The second relates to the ongoing costs of maintaining the new customer. These two kinds of costs vary by customer type, size, service voltage, and type of equipment used for access. Examples of the above costs include distribution-related investments for items such as transformers, service runs, meters, customer related O&M, Customer Service Distribution, A&G, GP and WC.

The marginal distribution customer cost methodology presented by SDG&E in prior electric marginal cost proceedings has been based on the Rental Method, as opposed to the "New Customer Only" ("NCO") Method that some parties have proposed in the past. In this proceeding, SDG&E will continue the use of the Rental Method to calculate unit marginal customer costs for the various customer classes, because it sends a more accurate and more reasonable price signal on the cost of providing an individual customer access to the electrical system. In the practical application of customer electricity rates, all customers pay a "rental" cost for the distribution customer-related equipment and other services necessary to maintain an account. The Rental Method follows the same process by applying the annualized investment cost and ongoing costs required to maintain the accounts of all customers. Conversely, the NCO Method understates the marginal distribution customer costs because this method takes the full cost per customer to hook up a new customer (not the annualized cost), multiplies that value only by the number of new customers estimated to be added in that class, and then divides this amount by the total number of customers in the class to get the unit cost per customer. This results in inefficient price signals to customers considering new hookups because the approach assures that new customers will never pay the full costs incurred to hook up to the utility's electric system. For this reason, the Rental Method is the better method to use to develop the marginal distribution customer costs in this proceeding.

SDG&E's updated marginal distribution customer costs are provided in Attachment A and consist of Transformer, Service and Meter ("TSM"), O&M, and Customer Service Distribution costs, as described below. Attachment D describes the changes in the development of the TSM costs used to calculate the updated marginal distribution customer costs presented in Attachment A compared to the updated marginal distribution customer costs filed in SDG&E's 2016 GRC Phase 2 (A.15-04-012) in April 2015.

In addition, as requested by the Administrative Law Judge's rulings made at the January 26, 2016 Pre-Hearing Conference in this proceeding (A.15-04-012), Attachment E presents the calculation of the marginal distribution customer costs based on the NCO Method that has been used by other parties in SDG&E's previous GRC Phase 2 proceedings, including the NCO Method assumptions used in those proceedings. These illustrative NCO Method marginal distribution customer costs are presented for comparison purposes only and are not being proposed by SDG&E for the reasons stated above.

B. Transformer, Service and Meter ("TSM") Costs

The customer investment costs for each customer type, customer size, and service voltage level were calculated using the TSM method. The TSM method includes transformers, services, and meters as the basis of the customer hookup costs. The installed costs for the TSM component are based on a detailed analysis of each individual component. Cost estimates for the various customer demand and service levels were developed for: 1) transformers based on transformer size and the average number of customers per transformer; 2) services based on wire size, number of runs, average service length, and compression lug wires; and 3) meters based on size and type (single- or three-phase). The TSM investment cost for each customer group was based on engineering estimates for a typical customer by size and class.

To determine the average TSM costs for each customer class, customers are grouped by maximum annual demand levels (in kW). Once grouped, the TSM costs for each customer demand level are calculated by multiplying the number of customers per demand level by the estimated demand-specific cost for each TSM component. A weighted average is then calculated for each TSM component that produces the average TSM cost per customer class.

Once developed, the TSM costs are multiplied by GP and WC loading factors. After receiving GP and WC loaders, the TSM costs are then converted to an annualized amount (dollars-per-customer-per-year) by using a RECC that calculates an annual economic rent.

C. Operations & Maintenance ("O&M") Costs

In order to develop a per-customer O&M cost allocation, SDG&E analyzed the 2013 Federal Energy Regulatory Commission ("FERC") Form 1 Distribution O&M account costs (FERC Accounts 580-598) to determine which portion of each account relates to distribution demand and which relates to customer connection. The customer-connection-related account amounts are totaled for the O&M costs.

SDG&E then allocates the customer-related O&M costs to the various rate schedules by using a factor derived from each schedule's percentage of the grand total of the estimated TSM cost. These amounts are then adjusted by an A&G factor before calculating the per-customer O&M cost.

D. Customer Service Distribution Costs

Customer Service Distribution Costs represent costs for such activities as customer service field, advanced metering, billing, credit & collections, branch office, customer contact center, residential customer services, commercial & industrial services, communications, and customer programs. The Customer Service Distribution Costs allocated for marginal distribution customer cost purposes in this proceeding reflect the 2013 Adjusted-Recorded costs identified in SDG&E's TY 2016 GRC Application.[4]

In accordance with the 2012 TY GRC Phase 2 Partial Settlement Agreement adopted by Decision ("D.") 14-01-002,[5] SDG&E conducted an internal study of historical SDG&E Customer Service Costs to determine the appropriate allocation of each type of costs for marginal distribution cost purposes. The results of the Customer Service Cost study are provided in Attachment C.

V. DISTRIBUTION REVENUE ALLOCATION

A. Distribution Revenue Allocation Background

SDG&E proposes to use the EPMC revenue allocation method as the basis to allocate the authorized distribution revenue requirement to customer classes. The EPMC method scales the customer class distribution marginal cost revenue responsibilities up or down by a single factor to ensure that the sum equals the authorized distribution revenue requirement.

Under SDG&E's distribution revenue allocation proposal, the authorized distribution revenue requirement, minus any revenues that are directly assigned to the particular customer classes,[6] is allocated among the customer classes based on the proposed marginal distribution cost revenue responsibilities by customer class. The customer class marginal costs revenue responsibilities for the distribution function is the sum of marginal customer, feeder and local distribution, and substation distribution costs. The unit marginal costs of distribution are multiplied by the appropriate cost drivers to develop the marginal distribution revenue

[4] Adjusted 2013 Customer Services Distribution Expenses presented in the SDG&E TY 2016 GRC Phase 1 (A.14-11-003) Direct Testimony of Khai Nguyen, Exhibit SDG&E-36, p. KN-A-31, Table KN-30.
[5] SDG&E TY 2012 GRC Phase 2 (A.11-10-002) October 4, 2012 Partial Settlement Agreement, Section 3.A – Marginal Costs, p. 4.
[6] SDG&E's directly assigned distribution revenues are labeled Non-Marginal Revenue Requirement Components and identified in Attachment B.2.

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allocations by customer class. Marginal customer cost revenues by customer class are developed by multiplying each class' unit marginal customer cost ($/customer/year) by the forecasted number of customers in that class. Total marginal feeder and local distribution cost revenues are developed by multiplying the unit marginal feeder and local distribution costs ($/kW/year) by the system non-coincident demand and the applicable loss factors. The customer class allocation of the marginal feeder and local distribution cost revenues is developed by multiplying the customer class' annual non-coincident demand, the applicable loss factors and the calculated ratio of the average class contribution to the peak demand at the circuit level (Effective Demand Factor or "EDF"). Total marginal substation cost revenues are developed by multiplying the unit marginal substation costs ($/kW/year) by the system non-coincident demand and the applicable loss factors. The customer class allocation of the marginal substation cost revenues is developed by multiplying the customer class' annual non-coincident demand, the applicable loss factors and the EDF at the substation level.

The sum of the marginal customer, feeder and local distribution, and substation distribution cost revenues is used to develop the distribution EPMC allocation factor. The EPMC allocation factor is then used to scale the marginal distribution class revenue allocations to equal the authorized distribution revenue requirement. The distribution revenue allocation by customer class is provided in Attachment B. Attachment B.1 presents the distribution marginal cost allocation factors by customer class. Attachment B.2 presents the allocation of distribution revenues to each customer class based on the distribution marginal cost allocations factors. Attachment B.3 presents the resulting distribution EPMC rates and revenues by customer class. Attachment D describes the changes to the calculation of the distribution revenue allocation presented in Attachment B compared to the updated marginal distribution revenue allocation filed in SDG&E's 2016 GRC Phase 2 (A.15-04-012) in April 2015.

B. Correction to Implementation of Method used for Distribution Revenue Allocation

In SDG&E's previous GRC Phase 2 proceeding (TY 2012 GRC Phase 2, A.11-10-002), SDG&E performed a study to determine the customer class' contribution to circuit and substation peak demands ("Circuit and Substation Study Requirement"), in compliance with D.08-02-034.[7] The Circuit and Substation Study Requirement stated the following:

> "An analysis, with affirmative testimony supporting the appropriate level of demand distribution billing determinants by class and the method of calculating those billing determinants for 1) substations, 2) feeders, and 3) new business (if included in demand, recognizing that the Farm Bureau also wants to analyze it as part of the customer hookup). Without prescribing the specifics of the study, the discussion at pages 10-11 and Attachment A of the Barkovich/Yap rebuttal testimony, PG&E's use of Peak Capacity Allocation Factors (PCAF), and the actual timing of substation demands should be considered. SDG&E should develop data to provide ten years of historical data for distribution and customer-related investment."[8]

SDG&E's TY 2012 GRC Phase 2 direct testimony addressed its compliance with the Circuit and Substation Study Requirement, including its proposal to incorporate the results of this study in the allocation of distribution revenues.[9] The study found each customer class' contribution to circuit and substation peaks based on 2008 load research data, developed the class EDFs based on dividing the class' load at the time of the circuit and substation peaks by the class' non-coincident demand based on the 2008 load research data, and then calculated an averaged class EDF by averaging the EDFs by customer class.

[7] D.08-02-034 adopted study requirements listed in Attachment A to SDG&E's Motion for Adoption of All Party and All Issue Settlement in SDG&E's TY 2008 GRC Phase 2 (A.07-01-047), including Compliance Requirement 6 requiring a study on class contribution to circuit and substation demands.
[8] SDG&E TY 2012 GRC Phase 2, A.11-10-002, Second Revised Prepared Direct Testimony of Cynthia Fang, Chapter 2, Attachment I – 2008 GRC Phase 2 Study Requirements, p. 11.
[9] SDG&E TY 2012 GRC Phase 2, A.11-10-002, Second Revised Prepared Direct Testimony of Cynthia Fang, Chapter 2, Attachment I – 2008 GRC Phase 2 Study Requirements, pp. 11 and 12.

In my direct testimony in the TY 2012 GRC Phase 2 proceeding, I proposed that marginal distribution demand-related costs be allocated to customer classes based on the estimated class' loads at the time of circuit and substation peaks.[10] The circuit and substation loads used were the class' loads coincident with circuit and substation peak loads based on the 2008 load research data identified in the Circuit and Substation Study Requirement results. For this reason, the allocation of distribution demand-related cost revenues proposed by SDG&E in the TY 2012 GRC Phase 2 proceeding, which provided one of the reference points for the settlement related to distribution revenue allocation agreed to by settling parties and adopted by D.14-01-002,[11] were based on the class' percentage of circuit and substation peak demands (i.e., estimated 2008 class' demand coincident with the time of the circuit and substation peaks divided by the total 2008 circuit and substation peak demands, respectively) multiplied by the TY 2012 forecasted system non-coincident demand determinants.

In developing the distribution revenue allocation proposal in this TY 2016 GRC Phase 2 proceeding, SDG&E realized that it had incorrectly applied the results of the Circuit and Substation Study Requirement in the allocation of the marginal distribution demand-related costs in the TY 2012 GRC Phase 2 proceeding. Although SDG&E incorporated the results from the Circuit and Substation Study Requirement in the allocation of distribution revenues, it inadvertently used the class' coincident peak demands based on the 2008 load research data from the study rather than using the average class EDFs developed in the study. Using the average class EDF multiplied by the class' TY 2012 forecasted non-coincident demand determinants to

[10] SDG&E TY 2012 GRC Phase 2 (A.11-10-002), Second Revised Prepared Direct Testimony of William G. Saxe, Chapter 3, p. WGS-3, lines 16-18.

[11] TY 2012 GRC Phase 2 (A.11-10-002), October 4, 2012, Partial Settlement Agreement, Section 3.B – Revenue Allocation, pp. 4-8.

allocate marginal distribution demand-related cost revenues in the TY 2012 GRC Phase 2 proceeding would have correctly captured the class' contribution to circuit and substation peaks based on class load diversity identified in the TY 2012 forecasted non-coincident demand determinants. The use of coincident peak demands based on the 2008 load research data from the Circuit and Substation Study Requirement to allocate marginal distribution demand-related revenues understated the responsibility of the residential class for these marginal distribution demand-related cost revenues and overstated the responsibility of the non-residential classes for these marginal distribution demand-related cost revenues that was presented in my TY 2012 GRC Phase 2 rebuttal testimony.[12] The correction to the implementation method used to allocate marginal distribution demand-related cost revenues to customer classes, that is the application of the class' EDFs rather than the application of the class' coincident peak demands in the TY 2016 GRC Phase 2 proceeding, appropriately bases the allocation on the class' average EDF multiplied by their TY 2016 forecasted non-coincident demand determinants. It should be noted that SDG&E's current electric rates, which reflect the implementation of D.14-01-002 adopting the partial settlement agreement on revenue allocation in SDG&E's TY 2012 GRC Phase 2 proceeding, correctly comport with the approved settlement.

VI. SUMMARY AND CONCLUSION

For the foregoing reasons, the updated marginal distribution demand and customer costs, as presented in Attachment A, as well as its proposal to use these marginal costs coupled with the EPMC method to allocate authorized distribution revenue requirements to customer classes, as presented in Attachment B, are reasonable and should be adopted by the Commission.

This concludes my prepared direct testimony.

[12] See, SDG&E TY 2012 GRC Phase 2, A.11-10-002, Prepared Rebuttal Testimony of William G. Saxe, Chapter 3, Attachment A.

VII. STATEMENT OF QUALIFICATIONS

My name is William G. Saxe. My business address is 8330 Century Park Court, San Diego, California 92123. I am employed as Project Manager III in the Customer Pricing Department of SDG&E. I have worked for SDG&E since February 2001. Prior to joining SDG&E, I was employed by Sempra Energy, the parent company of SDG&E, from April 1999 through January 2001. In addition, I was employed by the Illinois Commerce Commission ("ICC") from September 1990 through April 1999.

I received a Bachelor of Science degree in Economics from the University of Wisconsin-Madison in 1985. I received a Master of Business Administration degree, with a concentration in Finance, from the University of Wisconsin-Madison in 1990.

I have previously testified before this Commission on rate design, marginal cost and other issues. In addition, I have previously submitted testimony before the FERC and the ICC.

APPENDIX – GLOSSARY OF ACRONYMS

A&G	Administrative & General
Commission	California Public Utilities Commission
EDF	Effective Demand Factor
EPMC	Equal Percent of Marginal Costs
FERC	Federal Energy Regulatory Commission
GP	General Plant
GRC	General Rate Case
ICC	Illinois Commerce Commission
kW	Kilowatt
NCO	New Customer Only
NERA	National Economic Research Associates
O&M	Operations & Maintenance
RECC	Real Economic Carrying Charge
SDG&E	San Diego Gas & Electric Company
TSM	Transformer, Service and Meter
TY	Test Year
WC	Working Capital

ATTACHMENT A

MARGINAL DISTRIBUTION COSTS

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION COSTS

Proposed Distribution Marginal Unit Cost by Customer Class

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on Rental Method ($/Customer/Year):					1
2	Residential		$152.61			2
3	Small Commercial					3
4		0 - 5 kW	$327.81	$832.16		4
5		>5 - 20 kW	$600.92	$832.16		5
6		>20 - 50 kW	$1,267.71	$832.16		6
7		>50 kW	$1,766.15	$1,776.44		7
8		Average	$530.95	$967.06		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$2,351.56	$1,145.02	$8,131.77	11
12		500 - 12 MW	$5,718.65	$1,340.52	$14,356.92	12
13		> 12 MW		$2,080.23	$20,928.27	13
14		Average	$2,426.30	$1,244.41	$11,462.83	14
15						15
16	Agricultural					16
17		≤20 kW	$594.09	$966.08		17
18		>20 kW	$2,185.46	$1,115.35		18
19		Average	$1,019.73	$1,108.25		19
20						20
21	Lighting ($/Lamp/Year)		$12.95			21
22						22
23						23
24	Demand-Related Marginal Cost:					24
25	Feeders & Local Distribution Demand ($/kW/Year)		$77.97	$77.97		25
26						26
27	Substation Demand ($/kW/Year)		$22.05	$22.05		27
28						28
29	Total Demand-Related Marginal Cost ($/kW/Year)		$100.02	$100.02		29

Note: **Distribution Marginal Unit Cost by Customer Class**: the distribution marginal unit costs by customer class presented are from the Chapter 6 workpapers.

ATTACHMENT B

DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT B.1

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Marginal Cost Allocation Factor by Customer Class

Line No.	Customer Class (A)	Customer Marginal Cost Revenue ($000) (B)	Percentage Allocation (%) (C)	Demand-Related Marginal Cost Revenue ($000) (D)	Percentage Allocation (%) (E)	Total Distribution Marginal Cost Revenue ($000) (F)	Distribution Marginal Cost Allocation Factor (%) (G)	Line No.
1	Residential	$196,406	60.17%	$395,045	52.35%	$591,451	54.71%	1
2								2
3	Small Commercial	$65,519	20.07%	$91,333	12.10%	$156,852	14.51%	3
4								4
5	Medium/Large Commercial & Industrial	$58,991	18.07%	$259,014	34.32%	$318,005	29.42%	5
6								6
7	Agricultural	$3,467	1.06%	$8,016	1.06%	$11,482	1.06%	7
8								8
9	Lighting	$2,055	0.63%	$1,242	0.16%	$3,297	0.30%	9
10								10
11	System	$326,437	100.00%	$754,650	100.00%	$1,081,087	100.00%	11

Note:

(1) **Distribution Marginal Cost Allocation Factors by Customer Class**: the distribution marginal cost allocation factor by customer class presented are from the Chapter 6 Workpapers.
(2) **Customer Marginal Cost Revenue**: reflects customer-related distribution marginal costs.
(3) **Demand-Related Marginal Cost Revenue**: reflects feeder & local distribution and substation demand-related distribution marginal costs.

ATTACHMENT B.2

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Revenue Allocation by Customer Class

Line No.	Customer Class (A)	Updated Distribution Revenue Allocation: Distribution Allocation Factors (%) (B)	Non Marginal Distribution Revenue ($000) (C)	Marginal Distribution Revenue ($000) (D)	Total Distribution Revenue Allocation ($000) (E)	Current Total Distribution Revenue Allocation ($000) (F)	Percentage Change (%) (G)	Line No.
1	**Residential**	54.71%		$772,652	$772,652	$678,801	13.83%	1
2								2
3	**Small Commercial**	14.51%		$204,906	$204,906	$180,828	13.32%	3
4								4
5	**Medium/Large Commercial & Industrial**	29.42%	$8,509	$415,431	$423,940	$537,227	-21.09%	5
6								6
7	**Agricultural**	1.06%		$15,000	$15,000	$19,030	-21.18%	7
8								8
9	**Lighting**	0.30%	$4,912	$4,307	$9,219	$9,831	-6.22%	9
10								10
11	**System**	100.00%	$13,421	$1,412,296	$1,425,717	$1,425,717	0.00%	11
12								12
13	Distribution Revenue Requirement ($000):	$1,425,717						13
14								14
15	Non Marginal Revenue Requirement Components ($000):							15
16	Lighting Facilities Charge Revenues:	$4,912						16
17	Standby Revenues:	$5,579						17
18	Distance Adjustment Fee Revenues:	$2,930						18

Note:

(1) **Distribution Revenue Allocation by Customer Class**: the distribution revenue allocation by customer class presented are from the Chapter 6 Workpapers.
(2) **Updated Distribution Revenue Allocation**: allocation of the current distribution revenue requirement based on the marginal Distribution Allocation Factors presented in this Application.
(3) **Current Total Distribution Revenue Allocation**: allocation of current distribution revenue requirement based on the current class distribution allocation percentages reflected in current rates; rates . effective November 1, 2015, pursuant to SDG&E Advice Letter 2791-E.
(4) **Distribution Revenue Requirement**: the $1,425,717,000 Distribution Revenue Requirement reflects the current distribution revenues being collected in rates effective November 1, 2015, excluding revenues that have separate allocation treatment such as Self Generation Incentive Program ("SGIP"), Demand Response ("DR"), and Customer Service Initiative ("CSI") costs.
(5) **Non-Marginal Lighting Facilities Charge Revenues**: Lighting Facilities Charges of $4,912,000 are the annual lighting facilities revenues identified in the Lighting Model from SDG&E witness Christopher Swartz (Chapter 2) workpapers.
(6) **Non-Marginal Standby Revenues**: Standby Revenues of $5,579,000 are the standby revenues based on the forecasted standby determinants multiplied by the applicable current standby rates effective November 1, 2015, pursuant to SDG&E Advice Letter 2791-E.
(7) **Non-Marginal Distance Adjustment Fee Revenues**: Distance Adjustment Fees of $2,930,000 are the annual distance adjustment fees revenues based on the forecasted overhead and underground distance adjustment fee determinants in feet multiplied by the applicable current distance adjustment fees effective November 1, 2015, pursuant to SDG&E Advice Letter 2791-E.

ATTACHMENT B.3

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Equal Percentage of Marginal Cost ("EPMC") Rates and Revenue by Customer Class

Line No.	Customer Class (A)	Marginal Distribution Rate (B)	EPMC Distribution Rate (C)	EPMC Distribution Revenue Allocation ($000) (D)	Line No.
1	Residential				1
2	Customer Marginal Cost ($/Customer-Month)	$12.72	$16.61		2
3	Demand-Related Marginal Cost ($/Non-Coincident kW)	$8.06	$10.53		3
4	Total - Residential			$772,652	4
5					5
6	Small Commercial				6
7	Customer Marginal Cost ($/Customer-Month)				7
8	Secondary				8
9	0 - 5 kW	$27.32	$35.69		9
10	>5 - 20 kW	$50.08	$65.42		10
11	>20 - 50 kW	$105.64	$138.01		11
12	>50 kW	$147.18	$192.27		12
13	Secondary Total	$43.88	$57.32		13
14					14
15	Primary				15
16	0 - 5 kW	$69.35	$90.59		16
17	>5 - 20 kW	$69.35	$90.59		17
18	>20 - 50 kW	$69.35	$90.59		18
19	>50 kW	$148.04	$193.39		19
20	Primary Total	$70.41	$91.98		20
21					21
22	Demand-Related Marginal Cost ($/Non-Coincident kW)				22
23	Secondary	$9.55	$12.47		23
24	Primary	$9.50	$12.41		24
25	Total	$9.55	$12.47		25
26					26
27	Total - Small Commercial			$204,906	27
28					28
29	Medium/Large Commercial & Industrial				29
30					30
31	Secondary				31
32	≤500 kW	$195.96	$256.00		32
33	500 - 12 MW	$476.55	$622.55		33
34	Secondary Total	$202.51	$264.55		34
35					35
36	Primary				36
37	≤500 kW	$95.42	$124.65		37
38	500 - 12 MW	$111.71	$145.93		38
39	> 12 MW	$173.35	$226.46		39
40	Primary Total	$105.00	$137.17		40
41					41
42	Transmission				42
43	≤500 kW	$677.65	$885.26		43
44	500 - 12 MW	$1,196.41	$1,562.95		44
45	> 12 MW	$1,744.02	$2,278.33		45
46	Transmission Total	$1,031.47	$1,347.48		46
47					47
48	Demand-Related Marginal Cost ($/Non-Coincident kW)				48
49	Secondary	$10.45	$13.65		49
50	Primary	$10.39	$13.57		50
51	Total	$10.43	$13.63		51
52					52
53	Total - Medium/Large Commercial & Industrial			$415,431	53

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Equal Percentage of Marginal Cost ("EPMC") Rates and Revenue by Customer Class

Line No.	Customer Class (A)	Marginal Distribution Rate (B)	EPMC Distribution Rate (C)	EPMC Distribution Revenue Allocation ($000) (D)	Line No.
54					54
55	Agricultural				55
56	Customer Marginal Cost ($/Customer-Month)				56
57	Secondary				57
58	≤20 kW	$49.51	$64.68		58
59	>20 kW	$182.12	$237.92		59
60	Secondary Total	$73.69	$96.27		60
61					61
62	Primary				62
63	≤20 kW	$80.51	$105.17		63
64	>20 kW	$92.95	$121.42		64
65	Primary Total	$84.70	$110.65		65
66					66
67	Demand-Related Marginal Cost ($/Non-Coincident kW)				67
68	Secondary	$5.25	$6.86		68
69	Primary	$5.23	$6.83		69
70	Total	$5.25	$6.86		70
71					71
72	Total - Agricultural			$15,000	72
73					73
74	Lighting				74
75	Customer Marginal Cost ($/kWh)	$1.08	$1.41		75
76	Demand-Related Marginal Cost ($/kWh)	$4.86	$6.35		76
77	Total - Lighting			$4,307	77
78					78
79	Total-System				79
80	Customer Marginal Cost ($/Customer-Month)			$426,447	80
81	Demand-Related Marginal Cost ($/Non-Coincident kW)			$985,849	81
82	Total - System			$1,412,296	82

GRC Phase 1 Distribution Revenue Requirement	1,425,717
Non-Marginal Revenue Requiremen	13,421
Marginal Distribution Revenue Requirement Allocatio	1,412,296
Marginal Customer Distribution Revenue Requiremen	326,437
Marginal Demand-Related Distribution Revenue Requiremen	754,650
Total Marginal Distribution Revenue Requiremen	1,081,087
EPMC Allocation Factor	130.64%

Notes:

(1) **Distribution EPMC Rates and Revenues by Customer Class**: the distribution EPMC rates and revenues by customer class presented are from the Chapter 6 Workpapers.
(2) **Marginal Distribution Rate**: equals the marginal cost by class and by voltage level for demand-related margin cost divided by the class determinants.
(3) **EPMC Distribution Rate**: equals the Marginal Distribution Rate multiplied by the EPMC Distribution Allocation Factor.
(4) **EPMC Distribution Revenue Allocation**: equals the EPMC Distribution Rate multiplying by the applicable determinants.

ATTACHMENT C

CUSTOMER SERVICE COST ALLOCATION

ATTACHMENT C

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2
APPLICATION ("A.") 15-04-012
CUSTOMER SERVICES COST STUDY

SDG&E TY 2012 GRC Phase 2 Requirement From
Partial Settlement Agreement Adopted in Decision ("D.") 14-01-002

Background: the SDG&E TY 2012 GRC Phase 2 (A.11-10-002) Partial Settlement Agreement adopted in D.14-01-002 requires SDG&E to perform a study to determine the appropriate allocation of customer account and service costs by customer class for use in updating its marginal distribution customer costs in its next GRC Phase 2 proceeding.[1] In SDG&E's TY 2012 GRC Phase 2 proceeding, SDG&E allocated the customer account and service costs to customer classes based on the number of customers in each class. The purpose of the study requirement is for SDG&E to evaluate the different types of customer account and service costs to determine the most appropriate allocation of these costs for the purpose of updating marginal distribution customer costs.

In the development of marginal distribution customer costs in SDG&E's TY 2016 GRC Phase 2 proceeding, the customer service costs used are the 2013 Adjusted-Recorded Distribution Customer Services ("Customer Services") costs identified in SDG&E's TY 2016 GRC Phase 1 proceeding (A.14-11-003).[2] SDG&E evaluated each cost category that make up the Customer Services costs to determine how these costs were incurred or are expected to be incurred to provide service to the various customer classes. What the study showed was that in most cases the historical Customer Services cost data only provides information to allocate the costs to Residential and Non-Residential customers without the ability to identify the costs associated with each specific Non-Residential customer class (Small Commercial, Medium/Large Commercial & Industrial ("M/L C&I"), Agricultural, and Lighting). For this reason, it was necessary in most cases to select an approach to allocate the Non-Residential portion of the Customer Services costs to Non-Residential customer classes.

Below are cost categories that make up the Customer Services costs, including the study allocation results by customer class for each cost category[3]:

Customer Service Field ("CSF") Costs: Approximately $5.6 million in 2013 Adjusted-Recorded CSF costs. Based on average CSF job orders performed during 2011-2013, that includes job order details by customer classes, CSF costs are allocated 79.1% to Residential, 16.2% to Small Commercial, 3.7% to M/L C&I, 0.9% to Agricultural, and 0.1% to Lighting.

[1] October 5, 2012 Partial Settlement Agreement in SDG&E's TY 2012 GRC Phase 2 proceeding (A.11-10-002), Section 3.A – Marginal Costs, p. 4.
[2] 2013 Adjusted-Recorded Customer Services Electric Distribution Costs identified in SDG&E TY 2016 GRC Phase 1 (A.14-10-003) Direct Testimony of Khai Nguyen, Exhibit SDG&E-36, p. KN-A-31, Table KN-30.
[3] Please note that the percentages identified for each Customer Services cost category may not add up to 100% because of rounding.

Advanced Metering Operations ("AMO") Costs: Approximately $7.6 million in 2013 Adjusted-Recorded AMO costs. Based on estimated AMO work orders, that includes work order details by customer classes, AMO costs are allocated 27.4% to Residential, 28.9% to Small Commercial, 38.7% to M/L C&I, 4.9% to Agricultural, and 0.1% to Lighting.

Billing Costs: Approximately $3.3 million in 2013 Adjusted-Recorded Billing costs. Based on average billing work done in 2011-2013, the allocations of the Billing costs are allocated 65.3% to Residential and 34.7% to Non-Residential customers. Because the historical Billing data does not include details to determine how much of the 34.7% is associated with each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 34.7% Billing Costs based on each class' percentage of average 2011-2013 annual non-residential customers. The resulting allocation is 65.3% to Residential, 27.3% to Small Commercial, 5.2% to M/L C&I, 0.9% to Agricultural, and 1.3% to Lighting.

Credit & Collections Costs: Approximately $1.8 million in 2013 Adjusted-Recorded Credit & Collection costs. Based on average Credit & Collections payment and collection services performed during 2011-2013, the allocations of the Credit & Collection costs are allocated 89.8% to Residential and 10.2% to Non-Residential customers. Because the historical Credit & Collections data does not include details to determine how much of the 10.2% is associated with each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 10.2% Credit & Collection costs based on each class' percentage of average 2011-2013 annual non-residential customers. The resulting allocation is 89.8% to Residential, 8.0% to Small Commercial, 1.5% to M/L C&I, 0.3% to Agricultural, and 0.4% to Lighting.

Remittance Processing & Postage Costs: Approximately $3.4 million in 2013 Adjusted-Recorded Remittance Processing & Postage costs. Because these costs are associated with customers that receive paper bills, the current number of customers receiving paper bills was pulled resulting in an allocation of 85.6% to residential and 14.4% to Non-Residential customers. Because this data does not include details on the number of paper bills by each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 14.4% Remittance Processing & Postage costs based on each class' percentage of average 2011-2013 annual non-residential customer numbers. The resulting allocation is 85.6% to Residential, 11.3% to Small Commercial, 2.1% to M/L C&I, 0.4% to Agricultural, and 0.6% to Lighting.

Branch Offices Costs: Approximately $1.3 million in 2013 Adjusted-Recorded Branch Offices costs. Based on average Branch Office transactions performed during 2011-2013, the allocations of the Branch Office costs are allocated 94.3% to Residential and 5.7% to Non-Residential customers. Because the historical Branch Office transaction data does not include details to determine how much of the 5.7% is associated with each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 5.7% Branch Offices costs based on each class' percentage of average 2011-2013 annual non-residential customers. The resulting allocation is 94.3% to Residential, 4.5% to Small Commercial, 0.8% to M/L C&I, 0.1% to Agricultural, and 0.2% to Lighting.

Customer Contact Center Operations and Support Costs: Approximately $6.0 million and $1.5 million in 2013 Adjusted-Recorded Customer Contact Center Operations and Support costs, respectively. Based on average Customer Contact Center calls received during 2011-2013, the Customer Contact Center costs are allocated 93.9% to Residential and 6.1% to Non-Residential customers. Because the historical Customer Contract Center call data does not include details to determine how much of the 6.1% is associated with each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 6.1% Customer Contract Center Operations and Support costs based on each class' percentage of average 2011-2013 annual non-residential customers. The resulting allocation is 93.9% to Residential, 4.8% to Small Commercial, 0.9% to M/L C&I, 0.2% to Agricultural, and 0.2% to Lighting.

Residential Customer Services Costs: Approximately $4.7 million in 2013 Adjusted-Recorded Residential Customer Services costs. 100% of the Residential Customer Services costs should be allocated to Residential.

Commercial & Industrial ("C&I) Services Costs: Approximately $4.4 million in 2013 Adjusted-Recorded C&I Services costs. Based on an evaluation of the cost categories that make up the C&I services costs it was determined that approximately 39.1% of these costs is for the M/L C&I class, 1.3% is for the Small Commercial class, and the remaining 59.5% needs to be allocated to the Non-Residential classes based an appropriate allocation method. SDG&E proposes that the Non-Residential customer classes be allocated their portion of the 59.5% C&I costs based on the proposed distribution revenue allocation in this proceeding.[4] The resulting total allocation of C&I Services costs is 16.7% to Small Commercial, 81.3% to M/L C&I, 1.3% to Agricultural, and 0.8% to Lighting.

Communications, Research & Web Costs: Approximately $6.7 million in 2013 Adjusted-Recorded Communications, Research & Web costs. Based on a review of the cost categories it was determined that approximately $725,000 of these costs are directly assignable to Residential customers and approximately $204,000 of these costs are directly assignable to Non-Residential customers. Because details on the Communication, Research & Web costs associated with each customers class is not available, the directly assignable Non-Residential costs are allocated to the Non-Residential customer classes based on each class' percentage of average 2011-2013 annual non-residential customers. In addition, the $5.8 million in unassignable costs is allocated to all customer classes, including Residential, based on each class' percentage of average 2011-2013 annual total system customers. The resulting allocation is 87.4% to Residential, 9.9% to Small Commercial, 1.9% to M/L C&I, 0.3% to Agricultural, and 0.5% to Lighting.

Customer Programs & Projects Costs: Approximately $2.0 million in 2013 Adjusted-Recorded Customer Programs & Projects costs. Because these costs are mainly associated with demand response, SDG&E is proposing that the allocations of these costs be based on the current demand response allocation factors. The resulting allocation is 39.8% to Residential, 11.7% to Small Commercial, 47.5% to M/L C&I, 0.5% to Agricultural, and 0.5% to Lighting.

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[4] Because C&I Services costs are part of the Customer Services costs used in the development of the proposed distribution revenue allocation, the proposed distribution revenue allocation factors used to allocate the C&I Services costs are the factors prior to the inclusion of Customer Services costs.

Other Office and Shared Services Costs: Approximately $1.3 million in 2013 Adjusted-Recorded Other Office and Shared Services costs. SDG&E proposes to allocate these miscellaneous Customer Services costs based on the resulting combined allocation of the other Customer Services costs listed above. The resulting allocation is 67.9% to Residential, 13.6% to Small Commercial, 16.9% to M/L C&I, 1.2% to Agricultural, and 0.4% to Lighting.

ATTACHMENT D

REVISIONS TO 2016 MARGINAL DISTRIBUTION CUSTOMER COSTS AND DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT D

CHANGES TO 2016 MARGINAL DISTRIBUTION CUSTOMER COSTS AND DISTRIBUTION REVENUE ALLOCATION FILED APRIL 2015 IN A.15-04-012

A. **Transformers, Services and Meter ("TSM") Costs:** the Chapter 6 testimony and workpapers reflect the following changes in the development of the TSM costs used to calculate updated marginal distribution customer costs in this filing compared to the TSM costs used in SDG&E's 2016 GRC Phase 2 (A.15-04-012) filed in April 2015:

(1) <u>TSM Overhead Rates and Material, Labor and Equipment Costs ("Raw Costs")</u>: the overhead rates and raw costs used to fully load the TSM costs were changed to reflect 3rd Quarter 2013 overhead rates and raw costs instead of the 1st Quarter 2014 overhead rates and raw costs used in the 2016 GRC Phase 2 filed in April 2015. The change to 2013 overhead rates and raw costs was done to be consistent with the year of the costs used in the development of the TSM costs which are 2013 costs. In addition, the overheads rates were updated to include the travel/yard factor which was mistakenly left out of the overhead rates used in the 2016 GRC Phase 2 (A.15-04-012) filed in April 2015. The travel/yard factor is applied to both the labor and equipment costs to reflect the cost to load the truck(s) for the job and the travel time to the job site, including the fuel costs for the truck(s).

(2) <u>Transformer Costs</u>: in addition to the update of the overhead rates and raw costs applied to transformer costs, the transformer costs were also updated to reflect the inclusion of transformer direct and indirect labor installation costs which were mistakenly left out of

the transformer costs used in the 2016 GRC Phase 2 (A.15-04-012) filed in April 2015. These changes result in small increases to the cost of most transformers serving customers with max demand less than or equal to 100 kW and small decreases to the cost of most transformers serving customers with max demand greater than 100 kW.

(3) Service Costs: in addition to the update of the overhead rates and raw costs applied to service costs, the service costs were also updated to reflect changes to wire costs. These changes result in decreases to secondary and transmission service costs and small increases to primary service costs.

(4) Meter Costs: in addition to the update of the overhead rates and raw costs applied to meter costs, the meter costs were also updated to include additional labor hours for the installation of current transformers on electric meter panels > 400 amps. These changes result in increases to meter costs, especially non-residential meter costs because of the increased labored hours required to install current transformers, if applicable.

B. Distribution Revenue Allocation: the Chapter 6 testimony and workpapers reflect the following changes to the calculation of the distribution revenue allocation in this proceeding compared to the distribution revenue allocation calculated in SDG&E's 2016 GRC Phase 2 (A.15-04-012) filed in April 2015:

(1) Updates to Marginal Distribution Customer Costs: as explained above, the marginal distribution customer costs have been updated to reflect changes in TSM costs. These marginal costs are used to develop the distribution revenue allocation and thus, changes

to these costs result in changes to the proposed distribution revenue allocation, presented in Attachment B. The changes to the marginal distribution customer costs result in small decreases to the distribution revenue allocation for the residential, medium/large commercial & industrial ("M/L C&I"), and lighting customer classes and small increases to the distribution revenue allocation for the small commercial and agricultural customer classes.

(2) Standby Revenues: the distribution revenue allocation calculation reflects the addition of standby revenues in the non-marginal revenue category identified in Attachment B-2, line 17. Standby revenues were mistakenly left out of the distribution non-marginal cost revenues (i.e., distribution revenues directly assigned to a customer class) in the 2016 GRC Phase 2 (A.15-04-012) filed in April 2015, which resulted in an overstatement of the non-assigned distribution revenues that need to be collected in electric rates. This change results in small decreases to the distribution revenue allocation for the residential, small commercial, agricultural, and lighting customer classes and a small increase to the distribution revenue allocation for the M/L C&I customer class because standby revenues are included in the total distribution revenues for the M/L C&I class.

(3) Forecasted 2016 Customers: the forecasted 2016 annual customers have been updated in this filing to reflect changes in forecasted demands. The total number of annual customers did not change only the number of customer identified by kW level. Updates to the forecasted number of customers by kW level result in changes to the allocation of marginal distribution customer cost revenues, which are based on the number of

customers. This change results in small decreases to the distribution revenue allocation for all customer classes except the small commercial class which sees an increase to their distribution revenue allocation due to this change.

(4) Forecasted 2016 Non-Coincident Demand: the forecasted 2016 non-coincident demand determinants have been updated in this filing. Updates to the forecasted 2016 non-coincident demand determinants by customer class result in changes to the allocation of the marginal distribution demand cost revenues which are based on non-coincident demand. This change results in increases to the distribution revenue allocation for the residential, small commercial, agricultural, and lighting customer classes and a decrease to the distribution revenue allocation for the M/L C&I customer class.

ATTACHMENT E

ILLUSTRATIVE NEW CUSTOMER ONLY ("NCO") MARGINAL DISTRIBUTION CUSTOMER COSTS

ATTACHMENT E

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION CUSTOMER COSTS

Distribution Customer Marginal Unit Cost by Customer Class Based on New Customer Only ("NCO") Method
Illustrative Marginal Customer Costs --- Not Proposed by SDG&E

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on NCO Method ($/Customer/Year):					1
2	Residential		$98.44			2
3	Small Commercial					3
4		0 - 5 kW	$221.49	$420.14		4
5		>5 - 20 kW	$306.98	$420.14		5
6		>20 - 50 kW	$486.00	$420.14		6
7		>50 kW	$640.57	$614.99		7
8		Average	$282.14	$447.97		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$1,470.56	$820.39	$4,086.32	11
12		500 - 12 MW	$2,878.48	$916.81	$5,920.27	12
13		> 12 MW		$918.78	$8,100.44	13
14		Average	$1,499.58	$868.61	$5,106.22	14
15						15
16	Agricultural					16
17		≤20 kW	$402.99	$554.05		17
18		>20 kW	$918.66	$579.87		18
19		Average	$540.92	$578.64		19
20						20
21	Lighting ($/Lamp/Year)		$4.71			21

Note: **Distribution Customer Marginal Unit Cost by Customer Class Based on NCO Method**: the distribution customer marginal unit costs by customer class based on the NCO Method are being provided for comparison purposes, as requested by the Administrative Law Judge's rulings made at the January 26, 2016, Pre-Hearing Conference in this proceeding (A.15-04-012).