Application of San Diego Gas & Electric Company (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 19-03-___
Exhibit No.: _________

CHAPTER 5

PREPARED DIRECT TESTIMONY OF

WILLIAM G. SAXE

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 2019

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PREPARED DIRECT TESTIMONY OF
WILLIAM G. SAXE
(CHAPTER 5)

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") methodology to allocate the authorized distribution revenue requirement;
- **Section VI – Summary and Conclusion**: Provides a summary of recommendations; and
- **Section VII – Witness Qualifications**: Presents my qualifications.

My testimony also contains the following attachments:

- **Attachment A –** Marginal Distribution Costs;
- **Attachment B –** Distribution Revenue Allocation;
- **Attachment C –** Illustrative New Customer Only ("NCO") Marginal Distribution Customer Costs.

II. BACKGROUND

For more than 30 years, the California Public Utilities Commission ("CPUC") 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 proposed marginal distribution demand costs are based on the NERA Regression Method while the marginal distribution customer costs utilize the Rental Method. Recent SDG&E rate design proceedings, specifically its Test Year ("TY") 2008 General Rate Case ("GRC") Phase 2 (Application ("A.") 07-01-047), TY 2012 GRC Phase 2 (A.11-10-002), and TY 2016 GRC Phase 2 (A.15-04-012), were decided by settlement on revenue allocation and thus, 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 cost 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 system while marginal distribution customer costs reflect the cost of adding an additional customer to the electric distribution system. These marginal distribution costs are used as a frame of reference for the determination of cost-based rates when we design distribution rates to reflect the costs of providing utility service.

In addition, SDG&E is proposing that authorized distribution revenue requirements be allocated to customer classes using the updated marginal costs proposed in this TY 2019 GRC Phase 2 Application. Allocating authorized distribution revenue requirements based on marginal costs balances fairness and equity by providing customers clear and accurate price signals for the services they receive.

III. MARGINAL DISTRIBUTION DEMAND COSTS

A. Marginal Distribution Demand Cost Background

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

Consistent with its previous GRC Phase 2 proceedings, SDG&E will continue the use of the NERA Regression Method to calculate marginal feeder and local distribution and substation costs for the system as a whole. By definition, the NERA Regression Method uses ten years of historical and five years of forecasted distribution investments along with annual distribution system peak determinants in a regression methodology. The NERA Regression Method identifies the utility's cumulative incremental changes in distribution load peak data 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.

SDG&E's marginal distribution demand cost component includes distribution investment costs related to load and customer growth for the period 2005-2019. These marginal distribution demand costs do not include reliability investments, replacement costs, or customer access costs, because these costs are not considered growth-related.

The distribution demand investment cost component is derived in units of dollars-per-kW. To more accurately reflect the true cost of investment, the investment costs are adjusted by various loading factors. These loading factors reflect additional costs that are related to the addition of capacity to the distribution systems. Loading factors have been derived for Operations & Maintenance ("O&M"), Administrative & General ("A&G"), General Plant ("GP"), and Working Capital ("WC").

SDG&E's cumulative change in peak load data is based on distribution planning forecasted circuit and substation loads from 2005-2019.

B. Unit Marginal Feeder and Local Distribution Costs

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 SDG&E's system during a specific planning horizon. These facilities include poles, fixtures, capacitors, and overhead and underground conductors and devices.

The feeder and local distribution investments used in the NERA Regression Method were obtained from distribution capital budget forecasts for the period 2017 through 2019.[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 2005

[1] 2017-2019 Distribution Capital Budget Forecasts are found in the SDG&E TY 2019 GRC Phase 1 Direct Testimony of Alan F. Colton. *See* A.17-10-007, Revised SDG&E Direct Testimony of Alan F. Colton (Electric Distribution Capital) (December 2017), Ex. SDG&E-14-R/Colton at Appendix A.

through 2016 was used for the historical period. However, the extension given to filing this GRC Phase 2 Application allows for the use of actual 2017 data and thus, the NERA regression analysis will use historical distribution investment data from 2005-2017 and forecasted distribution investment data for 2018 and 2019. Because marginal costs reflect the cost to meet new demand on the system, 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 2020 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. Unit 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 system during a given period of time.

[2] 2020 escalations are the cost escalation factors presented in SDG&E TY 2019 GRC Phase 1 Direct Testimony of Scott R. Wilder. *See* A.17-10-007, Workpapers to Prepared Direct Testimony of Scott R. Wilder (October 2017), Ex. SDG&E-39-WP/Wilder.

The substation investments used to calculate marginal substation costs were obtained from capital budget forecasts for the period 2017 through 2019.[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 2005 through 2016 was used for the historical component. However, the extension given to filing this GRC Phase 2 Application allows for the use of actual 2017 data and thus, the NERA regression analysis will use historical distribution investment data from 2005-2017 and forecasted investment data for 2018 and 2019. Because marginal costs reflect the cost to meet new demand on the system, 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 2020 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.

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[3] 2017-2019 Distribution Capital Budget Forecasts are found in the SDG&E TY 2019 GRC Phase 1 Direct Testimony of Alan F. Colton. *See* Ex. SDG&E-14-R/Colton at Appendix A.

The first is the cost associated with the investment required to provide access (hook up) to a new 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 final line transformers ("transformers"), service drops, meters, customer related O&M, Customer Service Distribution, A&G, GP and WC.

Consistent with its previous GRC Phase 2 proceedings, SDG&E will continue the use of the Rental Method to calculate unit marginal customer costs for the various customer classes, which for SDG&E consists of residential, small commercial, medium/large commercial & industrial ("M/L C&I"), agricultural, street lighting classes, and the new school class being proposed in this proceeding.[4] As explained below in Section E, SDG&E proposes the use of the Rental Method because it believes it sends a more accurate and more reasonable price signal of the cost of providing an individual customer access to the electrical system compared to the other marginal distribution customer cost methodologies being considered.

B. Transformer, Service Drop 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, service drops, 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) service drops based on wire size, number of runs, average service length, and compression lug wires; and 3) meters

[4] The School class is proposed in the direct testimony of SDG&E witness Stein (Chapter 1).

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. These TSM costs are then adjusted for Rule 15/Rule 16 allowances that residential and non-residential customers receive to cover TSM installation costs. For residential customers, the Rule 15/Rule 16 allowance to cover TSM costs is currently $3,241 per customer hook-up;[5] thus, the residential TSM costs used in the marginal distribution customer cost calculation reflects a maximum TSM cost per residential customer of $3,241. For non-residential customers, the Rule 15/16 allowance is calculated separately for each customer;[6] thus, the non-residential TSM costs are adjusted for the average percentage of TSM costs paid by non-residential customers based on historical data, which is 19%.

Once developed, the TSM costs are multiplied by GP and WC loading factors. After receiving GP and WC loading, 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. O&M Costs

In order to develop a per-customer O&M cost allocation, SDG&E analyzed the Federal Energy Regulatory Commission ("FERC") Form 1 Distribution O&M account costs (580 to 598)

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[5] Rule 15 tariff, Sheet 4 (effective October 20, 2017) at Section C.3.
[6] *Id.* at Section C.4.

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 activities such as customer service field, advanced metering, billing, credit & collections, postage, branch office, customer contact center, residential customer services, business services, marketing and communication, and customer programs. The Customer Service Distribution Costs allocated for marginal distribution customer cost purposes in this proceeding are based on a study of historical SDG&E Customer Service Costs to determine the appropriate allocation of each type of Customer Service Distribution Costs identified in SDG&E's TY 2019 GRC Application.[7]

E. Support for Rental Method Adoption

SDG&E has consistently proposed the use of the Rental Method to calculate unit marginal distribution customer costs in GRC Phase 2 proceedings because the Rental Method sends a more accurate and more reasonable price signal of the cost of providing an individual customer access to the electrical system compared to the New Customer Only ("NCO") Method that some parties have proposed in those proceedings. In the billing of utility electricity rates, all

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[7] Adjusted 2016 Customer Services Distribution Expenses presented in the SDG&E TY 2019 GRC Phase 1 Direct Testimony of Khai Nguyen. *See* A.17-10-007, SDG&E Second Revised Direct Testimony of Khai Nguyen, Ex. SDG&E-42-2R/Nguyen, p. KN-A-29, Table KN-28.

customers pay a “rental” price for the distribution customer-related equipment or TSM costs necessary to maintain a customer account. For instance, residential customers do not pay the upfront incremental cost of the TSM assets necessary to provide them electric service but rather customers pay electric rates in their monthly utility bills to recover the cost of TSM assets. Therefore, by paying electric utility rates through monthly bills customers are essentially paying a monthly rental price for the TSM equipment installed to allow them to receive electric service.

The Rental Method follows this “rental” process by annualizing the cost of the TSM investments required to maintain the accounts of all customers and then converting this annual cost into a monthly amount. Conversely, the NCO Method understates the marginal distribution customer costs because this method takes the cost per customer to hook up a new customer (not the annualized cost), multiplies that value only by the number of estimated new and replacement customers for the customer class, and then divides this amount by the total number of customers in that class to get the unit cost per customer. This results in inefficient price signals to customers considering new hookups because this approach assures that new customers will never pay the full costs incurred to hook up to the utility’s electric system. Also, because the NCO Method calculation relies on the forecasted number of new and replacement customers, the resulting unit cost for TSM under the NCO Method varies considerably depending on the assumed customer class growth rates and not necessarily in response to changes in the TSM costs.

Attachment A presents SDG&E’s proposed marginal distribution customer costs based on the Rental Method. In addition, for comparison purposes, Attachment C presents illustrative SDG&E 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.[8]

V. DISTRIBUTION REVENUE ALLOCATION

SDG&E proposes to use the EPMC revenue allocation methodology to allocate the authorized distribution revenue requirement to customer classes. The EPMC methodology scales the customer class distribution marginal cost revenue responsibilities up or down by a single factor such 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,[9] 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 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

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[8] Pursuant to Decision ("D.") 17-09-035, the SDG&E TSM costs proposed in this proceeding will be used to calculate the Residential Eligible Fixed Costs in Phase 3 of SDG&E's 2018 Rate Design Window ("RDW") proceeding (A.17-12-013) based on the four marginal distribution customer cost methodologies used in that proceeding as directed in that decision (at 39): (1) Rental Method; (2) NCO Method; (3) Adjusted Rental Method 1 ("ARM 1"); and (4) Adjusted Rental Method 2 ("ARM 2").

[9] SDG&E's directly assigned distribution revenues are labeled Non-Marginal Revenue Requirement Components and identified in Attachment B.2.

the marginal feeder and local distribution cost revenues is developed by multiplying the total marginal feeder and local distribution cost revenues by the product of the customer class' annual non-coincident demand and the estimated 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 total marginal substation cost revenues by the product of the customer class' annual non-coincident demand and 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, and the resulting EPMC distribution rates based on those revenue allocations, is provided in Attachment B, attached herein. 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 EPMC distribution rates and revenues by customer class. One change in this GRC Phase 2 filing is the addition of the On-Peak Demand-Related Marginal Cost ($/On-Peak kW) category. As discussed in the direct testimony of SDG&E witness Stein (Chapter 1), pursuant to Ordering Paragraph ("OP") 33 of D.17-08-030 SDG&E is required to perform a distribution cost study to determine the percentage of its distribution costs that should be allocated to on-peak demand charges instead of non-coincident demand charges. The On-

Peak Demand-Related Marginal Costs presented in my workpapers reflect the results of this distribution demand study that SDG&E is required to file within 60 days of the filing of this Application.[10]

VI. SUMMARY AND CONCLUSION

SDG&E recommends that the CPUC adopt SDG&E's updated marginal distribution demand and customer costs, presented in Attachment A, and SDG&E's proposal to use these marginal costs coupled with the EPMC methodology to allocate authorized distribution revenue requirements, as presented in Attachment B.

This concludes my prepared direct testimony.

[10] Resolution E-4951 (September 13, 2018) at OPs 1 and 2.

VII. WITNESS QUALIFICATIONS

My name is William G. Saxe. My business address is 8330 Century Park Court, San Diego, California 92123. I am employed as Rates & Cost Studies Project Manager 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 the CPUC on rate design, marginal cost and other issues. In addition, I have previously submitted testimony before the FERC and the ICC.

ATTACHMENT A

MARGINAL DISTRIBUTION COSTS

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-0XX
MARGINAL DISTRIBUTION COSTS

Proposed Distribution Marginal Unit Costs

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on Rental Method:					1
2	Residential ($/Customer/Year)		$153.10			2
3						3
4	Small Commercial ($/Customer/Year)					4
5		0 - 5 kW	$238.53	$552.61		5
6		>5 - 20 kW	$426.95	$552.61		6
7		>20 - 50 kW	$952.81	$552.61		7
8		>50 kW	$1,402.70	$684.91		8
9						9
10	Medium/Large Commercial & Industrial ($/Customer/Year)					10
11		≤500 kW	$2,123.54	$1,004.80	$8,316.55	11
12		500 - 12 MW	$4,665.48	$1,102.35	$11,517.99	12
13		> 12 MW		$1,379.54	$15,844.99	13
14						14
15	Agricultural ($/Customer/Year)					15
16		≤20 kW	$457.32	$681.08		16
17		>20 kW	$1,423.09	$768.27		17
18						18
19	Lighting ($/Lamp/Year)		$12.18			19
20						20
21	School					21
22		Non-Lighting ($/Customer/Year)				22
23		≤20 kW	$512.37	$681.08		23
24		>20 kW	$2,433.96	$984.60		24
25						25
26		Lighting ($/Lamp/Year)	$12.18			26
27						27
28	Demand-Related Marginal Cost:					28
29	Feeders & Local Distribution Demand ($/kW/Year)		$52.05	$52.05		29
30						30
31	Substation Demand ($/kW/Year)		$19.61	$19.61		31
32						32
33	Total Demand-Related Marginal Cost ($/kW/Year)		$71.67	$71.67		33

Note: **Customer, Feeder & Local Distribution Demand and Substation Demand Unit Marginal Costs**: Customer, Feeder & Local Distribution Demand

ATTACHMENT B

DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT B.1

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-0XX
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	$201,756	65.9%	$170,712	41.5%	$372,467	51.9%	1
2								2
3	Small Commercial	$52,508	17.2%	$52,255	12.7%	$104,762	14.6%	3
4								4
5	Medium/Large Commercial & Industrial	$44,448	14.5%	$173,824	42.3%	$218,272	30.4%	5
6								6
7	Agricultural	$2,775	0.9%	$5,628	1.4%	$8,404	1.2%	7
8								8
9	Lighting	$1,961	0.6%	$876	0.2%	$2,837	0.4%	9
10								10
11	School	$2,596	0.8%	$7,660	1.9%	$10,256	1.4%	11
12								12
13	System	$306,044	100.0%	$410,955	100.0%	$716,999	100.0%	13

Note:

(1) **Customer Marginal Cost Revenue**: reflects customer-related distribution marginal costs.
(2) **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") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-0XX
DISTRIBUTION REVENUE ALLOCATION

Distribution Revenue Allocation by Customer Class

		Updated Distribution Revenue Allocation					Comparison to Current Allocation[2]		Comparison to 2016 GRC Phase 2 Proposed Allocation[3]		
Line No.	Customer Class (A)	Distribution Allocation Factors (%) (B)	Non Marginal Distribution Revenue ($000) (C)	Marginal Distribution Revenue ($000) (D)	Proposed Total Distribution Revenue Allocation ($000) (E)	Proposed Total Distribution Revenue Allocation (%) (F)	Current Total Distribution Revenue Allocation ($000) (G)	Percentage Change (%) (H)	SDG&E 2016 GRC Phase 2 Proposed Total Distribution Revenue Allocation ($000) (I)	Percentage Change (%) (J)	Line No.
1	**Residential**	51.95%		$732,756	$732,756	51.44%	$629,694	16.37%	$691,912	5.90%	1
2											2
3	**Small Commercial**	14.61%		$206,099	$206,099	14.47%	$224,775	-8.31%	$225,354	-8.54%	3
4											4
5	**Medium/Large Commercial & Industrial**	30.44%	$10,606	$429,407	$440,012	30.89%	$542,249	-18.85%	$478,672	-8.08%	5
6											6
7	**Agricultural**	1.17%		$16,532	$16,532	1.16%	$18,619	-11.21%	$17,555	-5.82%	7
8											8
9	**Lighting**	0.40%	$3,399	$5,582	$8,980	0.63%	$9,274	-3.16%	$11,118	-19.23%	9
10											10
11	**School**	1.43%	$54	$20,177	$20,231	1.42%	NA	NA	NA	NA	11
12											12
13	**System**	100.00%	$14,058	$1,410,553	$1,424,611	100.00%	$1,424,611	0.00%	$1,424,611	0.00%	13
14											14
15	Distribution Revenue Requirement ($000):	$1,424,611									15
16											16
17	Non Marginal Revenue Requirement Components ($000):										17
18	Lighting Facilities & Maintenance Charge Revenues (Non-School):	$3,399									18
19	Lighting Facilities & Maintenance Charge Revenues (School):	$28									19
20	Standby Revenues:	$7,100									20
21	Distance Adjustment Fee Revenues (Non-School):	$3,506									21
22	Distance Adjustment Fee Revenues (School):	$26									22

Note:

(1) Updated Distribution Revenue Allocation: allocation of the current distribution revenue requirement based on the marginal Distribution Allocation Factors presented in this Application.
(2) 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 January 1, 2019, pursuant to SDG&E Advice Letter 3326-E.
(3) 2016 GRC Phase 2 Proposed Total Distribution Revenue Allocation: total distribution revenue allocation based on the total distribution allocation factors proposed in SDG&E 2016 GRC Phase 2 (A.15-04-012) Rebuttal Testimony of William G. Saxe (Chapter 5) multiplied by the current total distribution revenue requirement.
(4) Distribution Revenue Requirement: the $1,424,611,000 Distribution Revenue Requirement reflects the current distribution revenues being collected in rates effective January 1, 2019, pursuant to SDG&E Advice Letter 3326-E, excluding revenues that have separate allocation treatment such as Demand Response ("DR") and Vehicle-Grid Integration ("VGI").
(5) Non-Marginal Lighting Facilities & Maintenance Charge Revenues: Lighting Facilities Charges of $3,399,000 for non-school and $28,000 for school are the annual lighting facilities and maintenance revenues identified in the Lighting Model from SDG&E witness William Saxe (Chapter 7) workpapers.
(6) Non-Marginal Standby Revenues: Standby Revenues of $7,100,000 are the standby revenues based on the forecasted standby determinants multiplied by the applicable current standby rates effective January 1, 2019, pursuant to SDG&E Advice Letter 3326-E.
(7) Non-Marginal Distance Adjustment Fee Revenues: Distance Adjustment Fees of $3,506,000 for non-school and $26,000 for school 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 January 1, 2019, pursuant to SDG&E Advice Letter 3326-E.

ATTACHMENT B.3

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-0XX
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)	$12.76	$25.10		2
3	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	$0.48	$0.94		3
4	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	$3.52	$6.92		4
5	Total - Residential			$732,756	5
6					6
7	Small Commercial				7
8	Customer Marginal Cost ($/Customer-Month)				8
9	Secondary				9
10	0 - 5 kW	$19.88	$39.10		10
11	>5 - 20 kW	$35.58	$70.00		11
12	>20 - 50 kW	$79.40	$156.21		12
13	>50 kW	$116.89	$229.96		13
14	Secondary Total	$32.79	$64.52		14
15					15
16	Primary				16
17	0 - 5 kW	$46.05	$90.60		17
18	>5 - 20 kW	$46.05	$90.60		18
19	>20 - 50 kW	$46.05	$90.60		19
20	>50 kW	$57.08	$112.28		20
21	Primary Total	$46.43	$91.35		21
22					22
23	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)				23
24	Secondary	$0.71	$1.40		24
25	Primary	$0.71	$1.39		25
26	Total	$0.71	$1.40		26
27					27
28	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				28
29	Secondary	$4.77	$9.38		29
30	Primary	$4.74	$9.33		30
31	Total	$4.77	$9.38		31
32					32
33	Total - Small Commercial			$206,099	33

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-0XX
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.
34					34
35	Medium/Large Commercial & Industrial				35
36					36
37	Secondary				37
38	≤500 kW	$176.96	$348.14		38
39	500 - 12 MW	$388.79	$764.87		39
40	Secondary Total	$183.07	$360.16		40
41					41
42	Primary				42
43	≤500 kW	$83.73	$164.73		43
44	500 - 12 MW	$91.86	$180.72		44
45	> 12 MW	$114.96	$226.16		45
46	Primary Total	$88.85	$174.80		46
47					47
48	Transmission				48
49	≤500 kW	$693.05	$1,363.43		49
50	500 - 12 MW	$959.83	$1,888.28		50
51	> 12 MW	$1,320.42	$2,597.66		51
52	Transmission Total	$914.20	$1,798.51		52
53					53
54	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)				54
55	Secondary	$1.01	$1.99		55
56	Primary	$1.00	$1.98		56
57	Transmission	$0.00	$0.00		57
58	Total	$1.01	$1.98		58
59					59
60	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				60
61	Secondary	$7.42	$14.60		61
62	Primary	$7.39	$14.53		62
63	Transmission	$0.00	$0.00		63
64	Total	$7.41	$14.59		64
65					65
66	Total - Medium/Large Commercial & Industrial			$429,407	66
67					67

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-0XX
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 ($000) (D)	Line No.
68	Agricultural				68
69	Customer Marginal Cost ($/Customer-Month)				69
70	Secondary				70
71	≤20 kW	$38.11	$74.97		71
72	>20 kW	$118.59	$233.30		72
73	Secondary Total	$58.76	$115.59		73
74					74
75	Primary				75
76	≤20 kW	$56.76	$111.66		76
77	>20 kW	$64.02	$125.95		77
78	Primary Total	$63.01	$123.97		78
79					79
80	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)				80
81	Secondary	$0.56	$1.10		81
82	Primary	$0.56	$1.09		82
83	Total	$0.56	$1.10		83
84					84
85	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				85
86	Secondary	$3.43	$6.76		86
87	Primary	$3.42	$6.72		87
88	Total	$3.43	$6.75		88
89					89
90	Total - Agricultural			$16,532	90
91					91
92	Lighting				92
93	Customer Marginal Cost ($/Lamp-Month)	$1.02	$2.00		93
94	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	$0.21	$0.41		94
95	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	$3.49	$6.87		95
96	Total - Lighting			$5,582	96
97					97

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-0XX
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 ($000) (D)	Line No.
98	School				98
99	Non-Lighting				99
100	Customer Marginal Cost ($/Customer-Month)				100
101	Secondary				101
102	≤20 kW	$42.70	$84.00		102
103	>20 kW	$202.83	$399.03		103
104	Secondary Total	$138.02	$271.54		104
105					105
106	Primary				106
107	≤20 kW	$56.76	$111.66		107
108	>20 kW	$82.05	$161.42		108
109	Primary Total	$79.38	$156.16		109
110					110
111	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)				111
112	Secondary	$0.87	$1.71		112
113	Primary	$0.86	$1.70		113
114	Total	$0.87	$1.71		114
115					115
116	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				116
117	Secondary	$4.38	$8.62		117
118	Primary	$4.36	$8.57		118
119	Total	$4.38	$8.61		119
120					120
121	Lighting				121
122	Customer Marginal Cost ($/Lamp-Month)	$1.02	$2.00		122
123	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	$0.24	$0.47		123
124	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	$4.38	$8.62		124
125	Total - Lighting				125
126					126
127	Total - School			$20,177	127
128					128
129	Total-System				129
130	Customer Marginal Cost ($/Customer-Month)			$602,080	130
131	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)			$42,256	131
132	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)			$766,216	132
133	Total - System			$1,410,553	133

GRC Phase 1 Distribution Revenue Requirement:	1,424,611
Non-Marginal Revenue Requirement	14,058
Marginal Distribution Revenue Requirement Allocation	1,410,553
Marginal Customer Distribution Revenue Requirement	306,044
Marginal Demand-Related Distribution Revenue Requirement	410,955
Total Marginal Distribution Revenue Requirement	716,999
EPMC Allocation Factor	196.73%

Notes:

(1) **Distribution EPMC Rates and Revenues by Customer Class**: the distribution EPMC rates and revenues by customer class presented are from the direct testimony workpapers of SDG&
witness William G. Saxe (Chapter 5).
(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

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

ATTACHMENT C

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-0XX
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		$107.77			2
3						3
4	Small Commercial					4
5		0 - 5 kW	$191.30	$368.90		5
6		>5 - 20 kW	$298.26	$368.90		6
7		>20 - 50 kW	$575.94	$368.90		7
8		>50 kW	$831.00	$436.97		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$1,858.10	$923.68	$5,713.44	11
12		500 - 12 MW	$3,898.17	$992.85	$7,365.96	12
13		> 12 MW		$1,012.52	$9,625.82	13
14						14
15	Agricultural					15
16		≤20 kW	$366.62	$498.62		16
17		>20 kW	$876.29	$542.17		17
18						18
19	Lighting ($/Lamp/Year)		$8.81			19
20						20
21	School					21
22		Non-Lighting ($/Customer/Year)				22
23		≤20 kW	$463.76	$498.62		23
24		>20 kW	$2,611.69	$509.10		24
25						25
26		Lighting ($/Lamp/Year)	$8.97			26

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 only.