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-15

PREPARED REBUTTAL TESTIMONY OF

WILLIAM G. SAXE

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

SECOND AMENDED APPLICATION

CHAPTER 5

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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PREPARED REBUTTAL TESTIMONY OF

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CHAPTER 5

I. OVERVIEW AND PURPOSE

The purpose of this rebuttal testimony is to respond to the direct testimony submitted by the Office of Ratepayer Advocates ("ORA") witnesses Nathan Chau and Louis Irwin, Utility Consumers Action Network ("UCAN") witnesses Garrick F. Jones and William Perea Marcus, The Utility Reform Network ("TURN") witness William Perea Marcus, California Farm Bureau Federation ("Farm Bureau") witness Laura Norin, Solar Energy Industries Association ("SEIA") witness R. Thomas Beach, The Federal Executive Agencies ("FEA") witness Maurice Brubaker, and California City-County Street Light Association ("CALSLA") witness Alison M. Lechowicz regarding marginal distribution customer and marginal distribution demand cost issues. Specifically, I will address recommendations raised by these witnesses and reach the following conclusions regarding those recommendations:

- The California Public Utilities Commission ("Commission") should adopt marginal distribution customer costs in this proceeding based on the Rental Method, proposed by San Diego Gas & Electric Company ("SDG&E") and supported by FEA, because it is the better methodology to use to calculate marginal distribution customer costs compared to the New Customer Only method ("NCO Method"), also called the One-Time Hookup Cost method ("OTHC Method"), proposed by ORA, UCAN, TURN, and CALSLA, as described in Section II.A;
- ORA's and UCAN's proposed adjustment to exclude costs associated with wildfire claims from the calculation of the Administrative and General ("A&G") Loading

Factor for Operations and Maintenance ("O&M") Non-Plant should be approved, but ORA's proposal also to exclude wildfire insurance costs should be rejected, resulting in a revised A&G Loading Factor for O&M Non-Plant of 29.71%, as described in Section II.B.1 and presented in Attachment C;

- UCAN's proposal to modify the O&M costs used in the development of the marginal distribution customer costs by offsetting these O&M costs with the $3,039,000 in 2016 forecasted revenues for service establishment, collection charges, and return check charges ("Miscellaneous Revenues") should be approved, with one modification (i.e., to apply this offset to ALL customers), resulting in an O&M cost offset of $2.10 per customer, as descried in Section II.B.5;
- UCAN's proposed adjustment to the Transformer, Service, and Meter ("TSM") Real Economic Carrying Charge ("RECC") factors used to calculate marginal distribution customer costs based on the Rental Method should be approved. In addition, SDG&E's proposed additional changes to the RECC factors, including updating the RECC meter factors to reflect the factors for smart meters (also referred to as Advanced Metering infrastructure ("AMI") meters) and replacing the use of the single weighted-average TSM RECC factor in the calculation of marginal distribution customer costs with the use of the individual TSM RECC factors (i.e., transformer RECC of 9.19%, service RECC of 8.31%, and average meter RECC of 11.62%) should be adopted, as described in Section II.B.6 and presented in Attachment D;
- The Commission should adopt the updated marginal distribution customer costs proposed by SDG&E, as presented in Attachment A and described in Section II.C, based on the Rental Method that reflects the adjustments to the: (a) A&G Loading

Factor for O&M Non-Plant, (b) O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, and (c) TSM RECC factors, mentioned above and described in more details in Sections II.B.1, II.B.5, and II.B.6, respectively;

- If the Commission adopts the marginal distribution customer costs based on the NCO Method, this method should reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant and (b) O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, mentioned above and described in more details in Sections II.B.1 and II.B.5, respectively. In addition, the NCO Method should be modified to include the following additional proposed adjustments: (a) ORA's proposal to base the annual new customer numbers on its average 2016-2019 forecasted new meter connections by customer class, as described in Section II.B.7, (b) SDG&E's proposal to use a replacement adder of 3.03% applied to all customers, as described in Section II.B.8, (c) UCAN's proposal to exclude meter replacement labor costs, as described in Section II.B.9, (d) SDG&E's proposal to modify the TSM Present Value Revenue Requirement ("PVRR") factor for meters to be based on the average PVRR for smart meters of 112.05%, as described in Section II.D, and (e) SDG&E's proposal to correct the calculation of the TSM costs per lamp for lighting customers, as described in Section II.D. The NCO Method results reflecting these adjustments are presented in Attachment E, and described in Section II.D;
- SDG&E's proposed updates to the 2014-2015 feeder and local distribution and substation costs to reflect the actual costs that are now available, as described in Section III.C, should be adopted for use in calculating SDG&E's marginal distribution demand costs;

- The load used in the calculation of SDG&E's marginal distribution demand costs should be changed from SDG&E's distribution-system loads to SDG&E's distribution planning forecasted loads, as described in Section III.E;
- The Commission should adopt the updated marginal distribution demand costs proposed by SDG&E, as presented in Attachment A and described in Section III.F, that reflect the adjustments to the (a) A&G Loading Factor for O&M Non-Plant, (b) 2014-2015 feeder and local distribution and substation costs to reflect actual costs, and (c) 2002-2016 load data to reflect distribution planning forecasted loads, described in Sections II.B.1, III.C, and III.E, respectively; and
- The Commission should adopt the updated Equal Percent of Marginal Costs ("EPMC") distribution revenue allocation proposed by SDG&E, as presented in Attachment B and described in Section IV, based on SDG&E's rebuttal testimony updates to the marginal distribution customer and marginal distribution demand costs mentioned above and described in more details in Sections II.C and III.F, respectively.

My rebuttal testimony is organized as follows:

- Section II – Marginal Distribution Customer Costs:
    - A. Rental Method versus NCO Method;
    - B. Marginal Distribution Customer Cost Calculation Adjustments;
    - C. SDG&E Proposed Updated Marginal Distribution Customer Costs Based on Rental Method; and
    - D. Revised Illustrative Marginal Distribution Customer Costs Based on NCO Method.

- Section III – Marginal Distribution Demand Costs:
  - A. Marginal Distribution Demand Cost Time-Period;
  - B. Updated SDG&E Distribution-System Loads for 2014-2016;
  - C. Additional SDG&E Proposed Updates to Marginal Distribution Demand Cost Analysis;
  - D. Distribution Demand Replacement Costs;
  - E. Use of Distribution Planning Forecasted Loads in the Marginal Distribution Demand Regression Analysis; and
  - F. SDG&E Proposed Updated Marginal Distribution Demand Costs.
- Section IV – SDG&E Proposed Updated Distribution Revenue Allocation.
- Section V – Summary and Conclusion

My rebuttal testimony also contains:

- Attachment A – SDG&E Proposed Updated Marginal Distribution Costs;
- Attachment B – SDG&E Proposed Updated Distribution Revenue Allocation;
- Attachment C – Revised A&G O&M Non-Plant Loading Factor;
- Attachment D – Revised TSM RECC and PVRR Factors;
- Attachment E – Revised Illustrative NCO Method Calculation Results;
- Attachment F – Revised 2002-2016 Distribution-System Loads and 2014-2015 Feeder & Local Distribution and Substation Costs; and
- Attachment G – Comparison of Marginal Distribution Demand Costs Based on Distribution-System Loads versus Distribution Planning Forecasted Loads.

II. MARGINAL DISTRIBUTION CUSTOMER COSTS

A. Rental Method versus NCO Method

1. Commission Decisions from Two Decades Ago Should Not Set the Precedent on Marginal Distribution Customer Cost Methodology

ORA, TURN, and CALSLA argue that the Commission already has decided in prior decisions that the NCO Method (also referred to as the "OTHC Method") is the better method to calculate marginal distribution customer costs. For this reason, these parties state that the Commission should not change its position on this issue and should continue to use the NCO Method to calculate marginal distribution customer costs in this proceeding.[1]

SDG&E disagrees with ORA, TURN, and CALSLA that prior Commission decisions that adopted the NCO Method, with the most recent of these decisions being issued approximately 20 years ago,[2] should set the precedent for the marginal distribution customer cost methodology adopted in this proceeding. SDG&E agrees with FEA that these claims are misplaced.[3] The methodology to use in developing marginal distribution customer costs has always been a contentious issue in rate design cases, with many twists and turns along the way. For instance, it is interesting to note that ORA actually supported the Rental Method over the NCO Method in the most recent decision cited that adopted the NCO Method, D. 97-12-044. The decision states that:

> *The Office of Ratepayer Advocates (ORA) objects to PG&E's method [NCO Method]* [4] *of allocating revenues for new customer*

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1 ORA Testimony, pp. 1-4 and 1-5; TURN Testimony, pp. 1-2 and 8-11; and CALSLA Testimony, pp. 4-5.

2 Decision (D.) 97-12-044.

3 FEA Testimony, p. 8.

4 In Pacific Gas & Electric Company's ("PG&E") most recent GRC Phase 2 proceeding (2017 GRC Phase 2 Application 16-06-013), PG&E proposed the Rental Method over the NCO Method.

hookups. This is because there is no apparent relationship between the costs imposed for access by a particular customer and the growth attributable to that customer's assigned class in earlier years. ORA raises a valid issue. Why should all of the customers in a particular class face higher or lower customer costs just because a certain number of new customers might be expected to join that class in the future? There is no causative relationship between the existing members of a particular rate class and the cost of a new hookup. Of course, the most efficient way to assign new hookup costs would be to charge each new customer the full cost of its new hookup. For several reasons, the Commission has not historically done that.[5]

This decision goes on to state that "[f]or now, we will adopt PG&E's approach [NCO Method]. However, in future proceedings, we will ask parties to help the Commission to respond more effectively to the equity concerns raised by this issue."[6] It is interesting that parties in this proceeding are trying to claim that theses prior decisions in non-SDG&E proceedings should be used as the basis for adopting the NCO Method in this proceeding, especially given the fact that the Commission clearly stated that it expects parties to present more information in future proceedings to ensure the marginal distribution customer cost methodology used fairly allocates distribution customer costs to customers.

For the reasons stated above, SDG&E recommends that the Commission base its decision on which methodology to use to calculate marginal distribution customer costs on the evidence

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5 D.97-12-044, p. 7.
6 D.97-12-044, pp. 7-8.

presented by parties in this proceeding and not on Commission decisions dating back at least two decades ago based on the evidence presented in those non-SDG&E proceedings. As discussed below, SDG&E believes that the Rental Method is the appropriate methodology to use in the development of marginal distribution customer costs in this proceeding because this methodology is based on marginal costs, provides accurate price signals regarding distribution customer costs, and provides more accurate and less volatile allocations of authorized distribution revenue requirements based on distribution customer costs.

2. Rental Method Based on Marginal Costs

ORA and TURN imply that the Rental Method is not based on marginal costs but is more of an embedded cost approach because it calculates the costs for all existing customer hook-up equipment.[7]

ORA and TURN appear to misunderstand the difference between marginal and embedded costs. Marginal customer costs reflect the incremental costs to serve the next customer whereas embedded customer costs reflect the historical costs incurred to serve customers. As explained in my direct testimony,[8] the Rental Method is based on the incremental TSM costs (not historical costs) to serve the next customer and thus, the Rental Method is based on marginal costs. In fact, the NCO and Rental methods use the same incremental TSM costs in the development of marginal distribution customer costs. The difference in these marginal distribution cost methodologies is the conversion of the incremental TSM costs into a cost per customer amount. The Rental Method using the RECC factors to annualize the cost of TSM assets correctly reflects the marginal cost of providing service to the next customer and correctly applies these marginal costs to all customers taking electric service from SDG&E. Applying

[7] ORA Testimony, p. 1-4; and TURN Testimony, pp. 2-3.
[8] SDG&E Direct Testimony of William G. Saxe, Chapter 6, pp. WGS-6 through WGS-9.

marginal costs to all customers does not result in the conversion of the same incremental TSM costs into embedded costs as ORA and TURN seem to imply. Conversely, the NCO Method does not calculate the marginal customer costs to provide service to the next customer but rather calculates the incremental change in total customer costs due to the expected customer growth rate of each customer class. Given its dependency on the customer growth rate by customer class the NCO Method provides customers with the more volatile TSM price signal compared to the Rental Method. As explained below, the NCO Method violates the concept of marginal cost pricing because zero customer growth for a customer class will result in a $0.00 marginal TSM price under the NCO Method while the Rental Method correctly identifies positive TSM costs for the next, or marginal, customer served in this customer class. For this reason, contrary to what ORA and TURN claim, the NCO Method is the distribution customer cost methodology that does not calculate the true marginal costs of the TSM assets for the next customer requiring service.

3. Rental Method Sends More Accurate Price Signal

ORA, TURN, and CALSLA imply that the Rental Method overcharges customers for the cost of their TSM equipment.[9] TURN witness Mr. Marcus goes on to argue that the Rental Method does not reflect a competitive market price because "…it prohibits purchasing equipment, or paying for it up front in hookup charges, and, thus, simulates a market with extreme barriers to entry by relevant participants in that market."[10] He compares the TSM equipment market to the housing market to argue that the Rental Method does not reflect economic reality because it requires everyone to be renters and thus, does not describe a

[9] ORA Testimony, p. 1-4; TURN, p. 7; and CALSLA, p. 5.
[10] TURN Testimony, pp. 1-2.

competitive market.[11] Mr. Marcus acknowledges that in a truly competitive market the TSM equipment costs would be fully paid by new customers when they are hooked up but because that is not the reality of the utility industry, the NCO Method also does not truly reflect a competitive market situation but in his perspective provides a second-best solution.[12]

ORA, TURN, and CALSLA are mistaken when they claim that the Rental Method does not provide an accurate price for TSM equipment and ends up overcharging customers for this equipment. Actually the opposite is true - the NCO Method based on forecasted customer growth rates by customer class assumed in the NCO Method calculations of ORA and UCAN undercharges customers for TSM costs. As explained above, both the Rental and NCO methods use the same incremental cost per TSM assets in their calculation of marginal costs. The Rental Method takes the purchase price of the TSM assets and converts it into a rental price based on the cost of the TSM assets. Conversely, the NCO Method takes that same purchase price of the TSM assets, multiplies it by the number of forecasted new customers and assumed TSM replacements in the customer class, and then divides this dollar amount by the number of total customers in the class to get a cost per customer that neither reflects a rental price or a purchase price of the TSM assets. ORA witness Chau seems to recognize this when he states that under the NCO Method, "[t]hese fully-loaded TSM costs are socialized (shared) by all customers within a class."[13] TURN witness Marcus also seems to understand that the NCO Method does not send the correct price signal to customers when he states that "…the most economically efficient method for capturing the costs of electric customer-access equipment would be in the form of a <u>customer</u> hookup fee that would charge the utility's access equipment costs to the

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[11] TURN Testimony, pp. 4-5.
[12] TURN Testimony, pp. 6-7.
[13] ORA Testimony, p. 1-7, lines 16-17.

customer at the time that the equipment is first installed,"[14] which Mr. Marcus acknowledges the NCO Method does not do because it assigns the customer hookup costs to the customer class.[15] For this reason, the Rental Method reflects an accurate rental price for TSM equipment to fully recover those costs from the customer whereas the NCO Method reflects an understated price that does not represent the cost of the TSM equipment and thus, will not fully recover the TSM costs from the customer.

ORA witness Chau implies that because the Rental Method collects a constant annual charge over the life of the TSM assets, this method provides a price based on the value of the TSM assets instead of its costs.[16] Again, as explained above, both the Rental and NCO methods use the same TSM costs. Through the use of the RECC factors to annualize the TSM costs, the Rental Method contains depreciation charges that account for the plant investment that is "used up," causing the need for eventual replacement. By annualizing the TSM costs, the Rental Method correctly provides an annual rental price to fully recover the cost of the TSM assets from the customer. Conversely, the NCO Method calculates a price for the TSM assets that varies considerably depending on the assumed customer class growth rate and not necessarily in response to changes in the TSM costs. For example, while ORA correctly identifies incremental unit TSM costs for the agricultural customer class, it calculates a TSM marginal price of $0 for agricultural customers under the NCO Method because the customer growth rate for the agricultural customer class is assumed to be zero.[17] This shows that the NCO Method is not a better approach for calculating marginal TSM costs as ORA claims because this method fails to calculate a positive marginal TSM price for agricultural customers despite the identification of

[14] TURN Testimony, p. 6.
[15] TURN Testimony, p. 7.
[16] ORA Testimony, p. 1-6.
[17] "ORA Testimony Chapter 1 Marginal Distribution Customer Access costs Consolidated Model.xlxs" workpaper file.

incremental TSM costs for agricultural customers. ORA witness Chau appears to understand this flaw with the NCO Method when he states that "[o]ften a floor of zero is imposed on the net growth rate to avoid calculating nonsensical negative marginal costs."[18] However, even imposing a customer class growth rate floor of zero as ORA did produces nonsensical results under the NCO Method, because a zero growth rate means a zero TSM marginal price. This clearly identifies one of the major flaws of the NCO Method, which is that under this marginal distribution customer cost methodology, results can change significantly from year to year based on changes in customer class growth rates rather than changes in TSM costs.

TURN witness Marcus is confused when he claims that the NCO Method better represents a competitive market compared to the Rental Method. Mr. Marcus tries to use the housing market as support for this claim by arguing that the Rental Method assumes that everyone is required to rent a home and no one is allowed to purchase a home, which does not reflect economic reality.[19] However, just the opposite is true. The housing analogy he uses actually provides support for the Rental Method not the NCO Method because the Rental Method correctly reflects the reality that all customers, whether owners or renters, face the same marginal costs. The marginal cost to both the owner and renter is the same because there is opportunity cost that an owner would incur by occupying the home equal to the rent that could be charged for the home. The same logic applies for renting versus purchasing TSM assets. Even if a customer decides to purchase TSM equipment, the Rental Method is still the appropriate method to use in the development of marginal distribution customer costs because it uses the RECC factors to annualize the cost of TSM assets, which correctly accounts for the opportunity cost of the purchase. In contrast, the NCO Method does not represent a competitive

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[18] ORA Testimony, p. 1-8, lines 14-15.
[19] TURN Testimony, p. 4.

market because it assumes that everyone purchases the TSM assets, which does not reflect the reality of the utility industry. More importantly, it fails to provide an efficient price signal for such assets because it only applies such costs to forecasted new customers and then divides these new customer costs over all customers (not just new customers) to derive a price that neither reflects the rental or purchase price of the TSM assets.

For the reasons stated above, the Rental Method not the NCO Method provides a more accurate price signal for TSM costs.

4. <u>Rental Method More Accurately Allocates Authorized Distribution Revenues</u>

ORA, TURN, and CALSLA claim that the NCO Method better reflects cost causation for TSM equipment because the NCO Method only considers TSM costs for new customers while the Rental Method overcharges customers for TSM equipment.[20] ORA, TURN, and CALSLA go on to argue against the Rental Method because they state that the Rental Method assigns marginal distribution customer costs to all customers even though TSM costs have little or no value once installed.[21] TURN witness Marcus states that "[a]ssigning hookup charges to the class, while a second-best solution from the point of view of economic efficiency, avoids subsidies among classes for these customer hookup charges because it assures that each class pays for its own hookups."[22] ORA witness Chau states that "…the assumptions built in to the Rental Method are nonsensical for hook ups since costs are covered entirely up-front pursuant to Rules 15 and 16."[23]

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20 ORA Testimony, pp. 1-4 through 1-7; TURN Testimony, pp. 5-7; and CALSLA Testimony, p. 5.
21 ORA Testimony, p. 1-6; TURN Testimony, pp. 3-4; and CALSLA Testimony, p. 5.
22 TURN Testimony, p. 7.
23 ORA Testimony, pp. 1-5, line 25 through 1-6, line 1.

The arguments provided by ORA, TURN, and CALSLA as to why the NCO Method reflects cost causation and improves economic efficiency would only have merit if SDG&E's customers actually paid for TSM costs upfront when getting hooked up for electric service. As stated above, this is not the case. Contrary to what ORA states, TSM hookup costs are not fully collected at the time of hookup. The Commission has adopted the concept of TSM allowances under Rules 15 and 16 that collect the TSM cost allowances over time from all customers through authorized revenue requirements based on customer hookup costs associated with the allowances provided under Rules 15 and 16. Basically, developers receive an allowance towards the cost of new customer hookups from SDG&E and these hookup costs are then recovered over time as part of the authorized distribution revenue requirement that SDG&E is proposing to allocate based on the marginal distribution customer costs adopted in this proceeding. The development of marginal distribution customer costs based on the Rental Method is in fact consistent with the Rule 15 and Rule 16 cost recovery methodology because it calculates the TSM marginal costs based on recovery of TSM costs from customers over the life of the TSM assets. Therefore, contrary to what ORA, TURN, and CALSLA claim, a marginal TSM price needs to be assigned to all customers to prevent subsidies associated with recovering TSM costs from occurring between customer classes, which the Rental Method correctly does and the NCO Method fails to do.

Because customers do not pay TSM hookup costs upfront prior to taking electric service from SDG&E, the Rental Method doesn't overcharge for customer connection costs as implied by parties but rather the NCO Method understates customer connection costs. As explained above, the NCO Method fails to calculate the marginal customer costs to provide service to the next customer but rather calculates the incremental change in total customer costs due to the assumed customer growth rate in each customer class. By applying TSM costs to only expected new customers in a given year and then dividing these incremental costs by all customers, the NCO Method is economically inefficient because it generally understates marginal distribution customer costs and thus, when applied for distribution revenue allocation purposes, understates the customer connection costs.

SDG&E agrees with FEA that applying the marginal distribution costs based on the NCO Method can lead to volatile distribution revenue allocations.[24] Customer classes that are growing rapidly during a given GRC Phase 2 period could experience large increases in distribution revenue allocations whereas customer classes that are growing less over that same period of time will experience much smaller distribution revenue allocations, independent of whether actual TSM costs have changed. This can result in significant revenue subsidies between customer classes based on the timing of when customer growth occurs within a class and not necessarily due to the cost of customer hookups incurred by SDG&E and reflected in its authorized distribution revenue requirement.

As stated above, another argument given by ORA, UCAN, CALSLA as to why the Rental Method does not calculate marginal cost is the claim that TSM assets have little if any value once installed because these assets have been installed to serve one customer. While SDG&E disagrees that the salvage value argument is important in deciding the appropriate marginal distribution customer cost methodology to use in this proceeding, SDG&E wants to at least respond to the notion that TSM assets have little or no value once installed. Obviously, smart meters have value because meters can be moved if a customer discontinued service with SDG&E. But more importantly is the fact that transformers, which reflect the majority of TSM costs, are generally installed to serve more than one customer (i.e., the smallest single-phase and

[24] FEA Testimony, p. 6.

three-phase transformers are assumed to serve 22 and 60 residential customers, respectively). A decrease in one customer would free up capacity on the transformer to serve other customers and thus, transformers clearly have value after installation. For this reason, the argument that the Rental Method somehow does not calculate marginal cost correctly because TSM assets have no value after installation has no merit.

For the reasons stated above, marginal distribution customer costs based on the Rental Method rather than the NCO Method will more accurately allocate authorized distribution revenues to customers.

B. Marginal Distribution Customer Cost Calculation Adjustments

1. Modification to A&G Loading Factor for O&M Non-Plant

ORA and UCAN propose adjustments to the A&G Loading Factor for O&M Non-Plant used in the calculation of marginal distribution customer costs.[25] ORA proposes to exclude what it defines as "extraordinary events" from the calculation of this A&G loader, specifically costs associated with wildfire claims and wildfire insurance. UCAN proposes revision to the Account 925 costs used in the calculation of this A&G loader based on SDG&E GRC Phase 1 (Application 14-11-003) Account 925 amounts, including the elimination of cost associated with wildfire claims.

SDG&E agrees with ORA and UCAN that costs associated with wildfire claims should be excluded from the calculation of this A&G loader because these wildfire claim costs are not expected to continue going forward. However, SDG&E disagrees with ORA's exclusion of wildfire insurance costs from this A&G loader because insurance costs associated with wildfires are forecasted to continue into the future. For this reason, SDG&E proposes that the Commission adopt the 5-year average A&G Loading Factor for O&M Non-Plant based on 2009-2013

[25] ORA Testimony, p. 1-13; and UCAN Testimony, pp. 20-21.

historical costs excluding costs associated with wildfire claims for use in calculating marginal distribution customer and demand costs, resulting in a change in the loading factor from 38.51% to 29.71%, as shown in Attachment C.

2. Accounts 586 and 587 O&M Costs

UCAN proposes to replace the 2009-2013 Accounts 586 and 587 costs in the 5-year average O&M calculation used in the calculation of marginal distribution customer costs with just the 2013 Accounts 586 and 587 costs because of changes in these costs due to AMI implementation, also referred to as smart meter implementation.[26] UCAN states that this change is needed because "[i]t is unreasonable to calculate marginal costs by averaging embedded costs reflecting past years when old technology was used that has already been supplanted."[27]

SDG&E disagrees with UCAN's proposal to modify the Accounts 586 and 587 O&M costs used in the development of O&M costs associated with marginal distribution customer costs. The O&M costs that SDG&E uses in the development of marginal distribution customer costs are 2013 costs that are allocated between customer-related and demand-related costs using the 5-year allocation factors based on 2009-2013 recorded O&M costs. Because Accounts 586 and 587 O&M costs are associated with meters, 100% of these costs are allocated to customer-related costs, which means that the specific Accounts 586 and 587 costs used in developing marginal distribution customer costs are 2013 costs, as UCAN suggests. However, UCAN is proposing to modify the 5-year O&M allocation factors used to allocate distribution O&M costs between customer-related and demand-related costs by using 2013 Accounts 586 and 587 costs for all five years. The reason that the allocation factors are developed based on an average of five years of distribution O&M cost data is to smooth out any anomalies that might occur in the

[26] UCAN Testimony, pp. 19-20.
[27] UCAN Testimony, p. 19.

costs in any given year. It would be inappropriate to modify the development of the 5-year allocation factors as UCAN suggests by replacing 2009-2012 Accounts 586 and 587 costs with 2013 costs because changes in Accounts 586 and 587 costs could have impacts on other distribution O&M Account costs used in the calculation. For this reason, it would be inconsistent to use a single year of costs (2013) for Accounts 586 and 587 instead of five years of costs (2009-2013) as is used for the other distribution O&M Accounts in the development of the 5-year O&M allocation factors. SDG&E recommends that the O&M allocations factors be based on an average of 2009-2013 O&M costs for all distribution Accounts and thus, the Commission should reject UCAN's proposal regarding the modification of Accounts 586 and 587 costs used in the development of the 5-year O&M allocation factors.

3. <u>Average Number of Residential Customers Served Per Transformer</u>

UCAN calculates an average number of residential customers per transformer based on SDG&E's TSM costs to be 9.32 customers and states that in response to UCAN DR 2-17, SDG&E indicated that the actual residential customers per transformer is 9.97 customers. For this reason, UCAN proposes to increase the number of residential customers per transformer for all customer sizes where the transformer serves four or more customers by 7%.[28]

SDG&E disagrees with UCAN's proposed change in the number of residential customers assumed to be served per transformer. In response to the referenced UCAN DR 2-17 data request, SDG&E provided the average number of residential customers at a given point in time, which happened to be 9.97 customers, whereas the 9.32 customer number reflects the average number of residential customers per transformer based on distribution planning engineering criteria regarding the number of customers by kW size that can be served on each type of transformer. For instance, the distribution planning engineering criteria indicates that as many as

[28] UCAN Testimony, p. 18.

22 residential customers with annual load between 0-2 kW and 60 residential customers with annual load between 0-2 kW are assumed to be served on a signal-phase 25 kW transformer and three-phase 75 kW transformer, respectively. It would be inappropriate to assume that the number of customers for every type of transformer serving four or more customers can be increased by 7% as UCAN proposes. Under UCAN's proposal, the number of 0-2 kW customers served on a single-phase 25 kW transformer and three-phase 75 kW transformer would be increased to approximately 24 and 64 customers, respectively, which is more customers than SDG&E's distribution planning engineering criteria identifies as should be served on these transformer types. For this reason, SDG&E recommends that the Commission reject UCAN's proposed adjustment to the number of residential customers per transformer because the number of customers SDG&E identified per transformer is supported by the distribution planning engineering criteria.

4. Tree Trimming and Pole Brushing Costs

UCAN proposes changes to O&M costs assigned to customer-related and demand-related distribution costs based on the percentage of tree trimming and pole brushing costs (within Account 593) assumed to be customer-related. UCAN proposes that tree trimming costs assigned to customer-related costs be reduced from approximately 12% to 2% and pole brushing costs assigned to customer-related costs be reduced from approximately 12% to 0%. UCAN states that based on the 5-year average of these costs, where tree trimming reflected 53.8% and pole brushing reflected 9.2% of Account 593 costs, this change reduces the allocation of Account 593 costs assigned to customer-related costs from about 12% to between 5-6%.[29]

SDG&E disagrees with UCAN's proposal to assign less of the tree trimming and pole brushing costs to customer-related costs. While SDG&E does not disagree that based on recent

[29] UCAN Testimony, p. 20.

historical data, less than 12% of tree trimming and pole brushing costs is associated with customer-related cost, SDG&E assigns the total O&M costs between customer-related and demand-related costs based on distribution plant assets. For this reason, it would inappropriate to assign tree trimming and pole brushing costs separately because total O&M costs are assigned to customer-related and demand-related costs based on a single allocation factor. Accepting UCAN's tree trimming and pole brushing cost proposal would require all O&M costs to be assigned to customer-related and demand-related separately, which is not possible because SDG&E does not have customer-related and demand-related splits for all O&M costs. This is the reason that SDG&E proposed the development of a single allocation factor for total O&M costs between customer-related and demand-related functions because this approach is possible and reasonable. For the reason stated above, SDG&E recommends that the Commission reject UCAN's proposal to allocate tree trimming and pole brushing costs separately because this approach is not workable and inconsistent with the allocation of other O&M costs.

5. O&M Cost Offset from 2016 Miscellaneous Revenues

UCAN states that "SDG&E has not included revenue offsets for several different types of miscellaneous revenue that it receives from tariffed service charges to customers (for service establishment, field collection, and returned check). These revenue credits offset costs paid by SDG&E for customer accounting and customer-related distribution O&M accounts." [30] For this reason, UCAN proposes to offset the marginal customer O&M costs used to develop the marginal distribution customer costs in this proceeding with the $3,039,000 in 2016 forecasted electric tariff service charge revenues ("Miscellaneous Revenues"), which results in an offset of

[30] UCAN Testimony, p. 22.

$2.111 per customer (except lighting customers, which UCAN states is highly unlikely to ever pay these fees) per year.[31]

SDG&E agrees with UCAN's proposal to use the 2016 Miscellaneous Revenues to offset O&M costs. Marginal costs should not reflect costs associated with Miscellaneous Revenues because these revenues are not included in base rate revenues and thus, UCAN's proposal to offset the forecasted 2016 O&M costs with the forecasted 2016 Miscellaneous Revenues is a reasonable approach to remove Miscellaneous Revenue costs from the O&M costs.

One modification that SDG&E proposes to UCAN's proposal is to apply this O&M cost offset to all customers, including the lighting customers that UCAN excluded from the offset. Because O&M costs are assigned to all customers, including lighting customers, SDG&E believes that this Miscellaneous Revenues offset should be applied to all customers. For this reason, SDG&E proposes that the Commission adopt a 2016 Miscellaneous Revenues offset of $2.10 per customer per year, based on dividing the $3,039,000 in forecasted 2016 Miscellaneous Revenues by the forecasted 2016 average number of total customers of 1,445,386, for use in calculating marginal distribution customer costs.

6. TSM RECC Factor

UCAN proposes that the weighted-average RECC factor calculation be modified to exclude the "Protective Devices & Capacitors" (Account 368.2) and "Installations on Customer Premises" (Account 371) equipment because neither of these items is required for customer-access and because these items were not included in the PVRR calculations for the NCO Method.[32]

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[31] UCAN Testimony, p. 22.
[32] UCAN Testimony, p. 23.

SDG&E agrees with UCAN's proposed weighted-average TSM RECC factor change. While the equipment UCAN identifies are used at least for some customer-access installations, SDG&E agrees that for consistency purposes, these equipment items should be eliminated in the weighted-average TSM RECC factor calculation. In addition, SDG&E proposes two other changes to the weighted-average TSM RECC factor calculation. First, the "Services Overhead" (Account 369.1) item also should be eliminated from the weighted-average RECC calculation because marginal distribution customer costs are based on underground service. Second, the RECC factors used for meters should be updated to reflect the factors for smart meters. Because SDG&E's meters have been replaced with smart meters pursuant to D.07-04-043, the RECC factors used should be changed to reflect the factors for smart meters, which are 11.72% for "Smart Meters" (Account 370.11) and 11.59% for "Meter Installations-Smart Meter" (Account 370.21). With the elimination of the TSM RECC factors for "Protective Devices & Capacitors," "Installations on Customer Premises," and "Services Overhead," and the change in the RECC factors for meters, the resulting weighted-average TSM RECC factor would be 9.40%, as presented in Attachment D. However, as explained below, SDG&E proposes to replace the use of the weighted-average TSM RECC factor with the use of the individual TSM RECC factors in the marginal distribution customer cost calculation.

For simplicity purposes, SDG&E has used the weighted-average TSM RECC factor in the calculation of marginal distribution customer costs based on the weighting of SDG&E's actual costs associated with TSM installations. However, the changes proposed to the weighted-average TSM RECC factor calculation raise the question of whether the use of a weighted-average TSM RECC factor is still appropriate, especially given the fact that the weighting itself no longer reflects actual SDG&E TSM installation costs with these changes. Applying a single weighted-average RECC factor assumes that the weighting of the TSM costs assigned customer classes are equal to the weighting of the TSM factor, which is not correct. For instance, TSM costs for some customers do not include transformer costs and/or meter costs and thus, it would be incorrect to use the weighted-average TSM RECC factor to calculate marginal distribution customer costs for these customers. For this reason, consistent with the use of individual TSM PVRR factors in the NCO Method, SDG&E recommends that the Commission adopt the individual TSM RECC factors, as presented in Attachment D, for use in calculating marginal distribution customer costs based on the Rental Method instead of a single weighted-average TSM RECC factor.

7. New Customer Calculation for NCO Method

ORA witness Nathan Chau argues that the use of the annual change in customers to forecast new customers in the NCO Method "…obscures the number of new connections since these growth rates fail to capture the number of new customers in isolation of those terminating service or switching schedules."[33] For this reason, ORA proposes to use its average 2016-2019 forecasted annual number of customers per customer class based on 2011-2015 new meter installations in the NCO Method.[34]

SDG&E agrees with ORA that new meter installations is a better representation of annual new customers that require new TSM hook ups. For this reason, SDG&E agrees that ORA's average 2016-2019 forecast of new customers per customer class based on SDG&E's historical 2011-2015 new meter installations should be used to develop the new customers by customer class in the calculation of marginal distribution customer costs under the NCO Method.

[33] ORA Testimony, p. 1-8, lines 9-11.
[34] ORA Testimony, pp. 1-8 through 1-11.

8. Replacement Cost Factor for NCO Method

ORA proposes to only include replacement costs associated with new connections made in a given year instead of basing the replacements on existing customer connections.[35] ORA states that replacement costs need to be included for new connections because these obligations impose the obligation to maintain that equipment going forward. However, ORA argues that replacement costs don't need to be included for existing connections because "…customer turnover and temporary vacancies do not impose any additional obligations to maintain the access equipment at the margin because this obligation was placed on the utility at the time of installation.[footnote excluded] Moreover, SDG&E did not include replacement costs in calculating marginal distribution demand costs 'because these costs are not growth related'."[36]

SDG&E disagrees with ORA that replacements associated with existing connections should not be included in the NCO Method calculation. Regardless of when the replacement obligation was imposed on SDG&E, the key is that SDG&E is obligated to replace TSM equipment when needed and thus, there is a cost associated with replacing this TSM equipment that should be included in the marginal customer cost calculation.

As mentioned above, ORA tries to support its decision to exclude replacements for existing connections by claiming that SDG&E did not include replacement costs in its marginal distribution demand cost calculation because these costs are not growth related. This comparison is not appropriate because marginal distribution demand costs are specifically driven by incremental demand, which is the reason replacement demand costs are not included in the calculation. SDG&E's marginal distribution demand costs are calculated by dividing incremental demand costs by incremental distribution load and thus, replacement costs should

35 ORA Testimony, p. 1-12.
36 ORA Testimony, p. 1-12, lines 9-14.

not be included in the marginal distribution demand cost calculation, as explained in Section III.D below. Conversely, marginal distribution customer costs are looking at costs associated with adding a customer to the SDG&E distribution system, which should include both the incremental costs of the TSM assets and the costs for the eventual replacement of those assets in the calculation. Through the use of the RECC factors to annualize the TSM costs, the Rental Method contains depreciation charges that account for the plant investment that is "used up," causing the need for eventual replacement.

If the NCO Method is ultimately adopted by the Commission in this proceeding, SDG&E agrees with UCAN[37] that the NCO calculation should reflect replacements applied to all customers and not just new connections as ORA proposes. In Attachment E of my February 9, 2016 direct testimony (Chapter 6), I presented an illustrative NCO Method calculation that had been used by parties in SDG&E's previous GRC Phase 2 proceedings that included a replacement rate of 1.5%.[38] SDG&E believes that the 1.5% replacement rate was used because this replacement rate had been adopted in one of the more recent Commission decisions adopting the NCO Method that parties cite.[39] SDG&E recommends that this replacement rate be updated based on the current book lives of SDG&E's TSM assets, which are 33 years for transformers (resulting in a replacement rate of 3.03%), 48 years for underground services (resulting in a replacement rate of 2.08%), and 15 years for meters (resulting in a replacement rate of 6.67%). Based on these TSM replacement rates applied to total TSM costs by customer class, the weighted-average replacement rate by customer class would actually be different by customer class due the differences in TSM costs by class. However, SDG&E is not proposing to establish class different replacement rates. Instead, for simplicity purposes, SDG&E recommends that the

[37] UCAN Testimony, pp. 24-25.
[38] SDG&E 2012 GRC Phase 2, A.11-10-002, Testimony of Division of Ratepayer Advocates, p. 3-14.
[39] D.97-03-017, p. 34.

Commission adopt a 3.03% replacement rate to use in the calculation of marginal distribution customer costs under the NCO Method because this is the replacement rate based on the book life of SDG&E transformers, which represents the majority of the TSM costs to serve most SDG&E customers.

9. Exclusion of Meter Replacement Labor Costs

UCAN proposes removing meter-replacement labor costs in the NCO Method because the labor costs for replacement of meters is already included in the O&M costs used in the marginal distribution customer cost calculation.[40]

SDG&E agrees with UCAN's proposal to exclude labor costs from the meter replacement costs included in the NCO Method calculation. For this reason, SDG&E recommends that the Commission approve the reduction in average replacement meter costs by customer class, as proposed by UCAN, for use in calculating marginal distribution customer costs under the NCO Method.

C. SDG&E Proposed Updated Marginal Distribution Customer Costs Based on Rental Method

SDG&E's proposed updated marginal distribution customer costs based on the Rental Method in this rebuttal testimony, as shown in Attachment A, reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant, (b) O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, and (c) TSM RECC factors, described above. SDG&E recommends that the Commission adopt SDG&E's proposed updated marginal distribution customer costs based on the Rental Method, as presented in Attachment A.

[40] UCAN Testimony, pp. 23-24.

D. Revised Illustrative Marginal Distribution Customer Costs Based on NCO Method

As stated above, SDG&E disagrees with the use of the NCO Method to calculate marginal distribution customer costs in this proceeding and recommends that the Commission adopt SDG&E's proposed updated marginal distribution customer costs based on the Rental Method, presented in Attachment A. However, if the Commission decides to adopt the NCO Method for allocating marginal distribution customer costs in this proceeding, the NCO Method calculation should reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant, (b) O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, (c) replacement adder of 3.03% for all customers, and (d) exclusion of labor costs for meter replacements, described above. In addition, as mentioned above, SDG&E proposes changes to the TSM RECC factors for meters to reflect the RECC factors for smart meters. For consistency purposes, SDG&E also proposes to change the PVRR factors for meters to reflect the PVRR factors for smart meters, which are 112.99% for "Smart Meters" (Account 370.11) and 111.72% for "Meter Installations-Smart Meter (Account 370.21) resulting in a weighted-average PVRR factor of 112.05% for smart meters, as shown in Attachment D. Finally, the revised NCO Method calculations should also reflect a correction to the illustrative NCO calculation for lighting customers provided in Attachment E of my direct testimony (Chapter 6). The NCO calculation for lighting customers mistakenly labeled the TSM costs as the "costs per customer," when in fact these costs were the "costs per lamp," which resulted in the marginal distribution customer costs for lighting customers to be understated when these costs were applied under the NCO Method. The revised illustrative NCO calculation results presented in Attachment E reflect the six adjustments described above.

III. MARGINAL DISTRIBUTION DEMAND COSTS

A. Marginal Distribution Demand Cost Time-Period

ORA states that SDG&E deviates from the standard practice recommended by the National Economic Research Associates ("NERA") by using 12 years of historical data (2002-2013) and only 3 years of forecasted data (2014-2016) in its marginal distribution demand cost regression analysis without providing justification for this change. ORA argues that 2002 and 2003 data should be excluded from the marginal distribution demand cost regression analysis because these years were right in the midst of the California energy crisis recovery period, and adding these years influences the load trend, substantially bumping the entire trend upward. For this reason, ORA proposes to only include 10 years of historical data (2004-2013) and 3 years of forecasted data (2014-2016) in its marginal distribution demand cost regression analysis.[41]

SDG&E agrees with the Farm Bureau that there is no need to remove 2002 and 2003 data from the marginal distribution demand cost regression analysis because these years are not outliers, as ORA claims.[42] ORA only considered the change in load when it deemed these years to be outliers, but as the Farm Bureau correctly states, the important thing to look at is the ratio of incremental distribution investment to incremental load, which shows 2002 and 2003 are not outliers.

ORA is correct that the NERA regression methodology recommends using 10 years of historical and 5 years of forecasted data. However, as explained in my direct testimony, SDG&E only had 3 years of forecast data available, which is the reason SDG&E chose in this proceeding (as it has in its previous two GRC Phase 2 proceedings) to use 12 years of historical data in the regression analysis to maintain the fifteen data points (12 years of historical data and 3 years of

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[41] ORA Testimony, pp. 2-2 and 2-3.
[42] Farm Bureau Testimony, p. 42.

forecasted data).[43] SDG&E believes that maintaining a sufficient number of data points for the regression analysis is important, which is the reason it chose to maintain the fifteen years of data points that the NERA methodology recommends by including two additional years of historical data.

For the reasons discussed above, the Commission should reject ORA's proposal to eliminate the 2002 and 2003 data from the marginal distribution demand cost regression analysis.

B. Updated SDG&E Distribution-System Loads for 2014-2016

ORA proposes that the 2014 forecasted distribution-system load that SDG&E included in its marginal distribution demand cost calculation should be updated to reflect the SDG&E actual weather-normalized 2014 distribution-system load, which is now available.[44] ORA also proposes to update the forecast for SDG&E's 2015 and 2016 distribution-system loads used to calculate marginal distribution demand costs with the California Energy Commission ("CEC") 2015 revised forecasts for those years.[45]

SDG&E agrees with ORA that the 2014 forecasted distribution-system load should be updated to reflect SDG&E's actual weather-normalized 2014 distribution-system load because this load data is now available. As explained in the rebuttal testimony of SDG&E witness Kenneth E. Schiermeyer, SDG&E proposes a modification in its weather-normalization process.[46] SDG&E's proposed actual weather-normalized 2014 distribution-system load of 4,279 MW is lower than the 4,365 MW that ORA proposes because of the change in SDG&E's weather-normalization process.

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[43] SDG&E Direct Testimony of William G. Saxe, Chapter 6, p. WGS-4, lines 19-22.
[44] ORA Testimony, pp. 2-4 and 2-5.
[45] ORA Testimony, pp. 2-5 through 2-7.
[46] SDG&E Rebuttal Testimony of Kenneth E. Schiermeyer, Chapter 4.

SDG&E also agrees with ORA that the 2015 and 2016 distribution-system loads used in the marginal distribution demand cost analysis should be updated to reflect the most current load information available. Because SDG&E's actual 2015 distribution-system load data is now available, SDG&E proposes that its forecasted 2015 distribution-system load should be updated to reflect SDG&E's actual 2015 weather-normalized load, as ORA proposes. Regarding the 2016 forecasted distribution-system load, SDG&E agrees with ORA that the 2016 forecasted load should be based on the CEC 2015 revised forecast for 2016 adjusted for transmission load and Additional Achievable Energy Efficiency ("AAEE"), as ORA proposes. SDG&E's proposed updated 2016 forecasted load of 4,438 MWs is a little higher than ORA's proposed 2016 forecasted load of 4,414 MWs because of lower calculated transmission load due to the modification to SDG&E's weather-normalization process, as described in Mr. Schiermeyer's rebuttal testimony. SDG&E's revised weather-normalized 2014-2015 and revised forecasted 2016 distribution-system loads are presented in Attachment F.

C. Additional SDG&E Proposed Updates to Marginal Distribution Demand Cost Analysis

As stated above, SDG&E is proposing a modification to its weather-normalization process, as addressed in the rebuttal testimony of Mr. Schiermeyer. For this reason, SDG&E proposes revisions to the 2002 through 2015 weather-normalized actual distribution-system loads to reflect this modified weather-normalization process change. Attachment F presents the revised 2002-2015 weather-normalized and 2016 forecasted distribution-system loads.

In addition, SDG&E proposes to update the feeder and local distribution and substation costs used in the marginal distribution demand cost regression analysis to reflect actual 2014 and 2015 distribution cost data. As mentioned above regarding the updates to the distribution-system load data, SDG&E now has actual 2014 and 2015 data and thus, SDG&E believes the marginal distribution demand cost regression analysis should be updated to reflect actual 2014 and 2015 cost data. Attachment F presents the revised feeder and local distribution and substation costs proposed by SDG&E for use in its marginal distribution demand cost analysis.

D. Distribution Demand Replacement Costs

UCAN proposes that marginal distribution demand costs should include SDG&E's marginal distribution capital replacement costs. UCAN states that "[b]y not including replacement costs, SDG&E's marginal cost methodology assumes that, once a piece of equipment is added, the utility will always replace that equipment, yet the future customers who benefit from the replacement—through receiving continued service—will never have to pay for it. Instead, the cost of the equipment would be recovered from all current customers as a non-marginal cost included in the EPMC multiplier."[47] UCAN goes on to state that "…SDG&E's view of this issue is based on the assumption that marginal cost <u>only</u> applies to <u>new demand</u> and not to the retention of existing demand….It is not reasonable to assume that customers in areas without load growth should bear no responsibility for the cost of O&M and capital maintenance replacements necessary to keep the existing system available for their use."[48] For this reason, UCAN proposes the inclusion of replacement distribution demand costs, which it finds to be about 50% of SDG&E's capital spending on the distribution system, as it identifies in Table 9.

SDG&E disagrees with UCAN that distribution demand costs not associated with load growth, such as replacement costs, should be included in the calculation of marginal distribution demand costs. UCAN appears to misunderstand the purpose of developing marginal distribution demand costs in this proceeding, which is to develop a marginal cost per kW to add incremental

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[47] UCAN Testimony, pp. 25-26.
[48] UCAN Testimony, p. 28.

demand to the SDG&E distribution system. These marginal costs are developed by regressing the incremental distribution demand costs needed to add load to the distribution system by the incremental distribution load added. Replacement costs should not be included in these marginal costs because these replacement costs are not associated with the incremental load being added to the distribution system. The annual $/kW marginal distribution demand costs based on the RECC factors contains depreciation charges that account for the eventual replacement of the distribution demand investment made to meet the load growth. For this reason, the marginal distribution demand cost calculation should only reflect the cost of adding demand to the distribution system and thus, should exclude costs not associated with load growth such as replacement costs as SDG&E's calculation correctly does.

UCAN incorrectly argues that not including replacement costs in the marginal distribution demand cost analysis results in future customers not having to pay for the cost of substation and feeder & local distribution costs and customers in areas without load growth not paying for the costs to maintain the existing distribution system for their use. This is not correct because SDG&E is developing an annual $/kW for substations and feeder & local distribution costs that applies to all customers, both existing and future customers, and customers in high-growth and low-growth areas.

UCAN also implies that by not including replacement costs in the marginal distribution demand costs, SDG&E is understating marginal distribution demand costs and thus, overstating the EPMC multiplier. However, just the opposite is true. UCAN is overstating the marginal distribution demand costs by including replacement costs because it inconsistently adds distribution demand costs without adjusting the load used in the marginal distribution demand regression analysis to reflect the costs added. As described above, replacement costs should not be included in the marginal distribution demand cost analysis because these marginal costs should be based on adding load. However, if replacement costs are included, the distribution load used in the marginal distribution demand regression analysis needs to be adjusted to include the distribution load associated with the replacement costs. By increasing distribution demand costs used in the marginal distribution demand cost regression analysis to reflect the addition of replacement costs but not increasing the distribution load to reflect the inclusion of these distribution replacement costs, UCAN significantly overstates the marginal distribution demand costs and thus, understates the EPMC multiplier.

For the reasons stated above, the Commission should reject UCAN's proposal to include distribution replacement costs in the calculation of marginal distribution demand costs.

E. Use of Distribution Planning Forecasted Loads in the Marginal Distribution Demand Regression Analysis

SEIA questions why SDG&E calculates its marginal distribution demand costs by using a regression of distribution investments versus annual distribution peak loads, instead of distribution investments versus non-coincident demand. SEIA states that "[i]t would be fundamentally inconsistent for the utility to calculate its distribution marginal costs on the basis of the annual peak demand on the distribution system, yet to charge customers for those costs based 100% on individual customer's non-coincident demands." [49]

The purpose of the marginal distribution demand cost regression analysis is to calculate the marginal demand costs ($/kW) based on incremental load added to the SDG&E distribution system. In the marginal distribution cost regression analysis, SDG&E used its distribution-system load to determine the annual incremental load added to the SDG&E distribution system. As stated in the direct testimony of SDG&E witness John Baranowski, SDG&E's distribution

[49] SEIA Testimony, p. 29, lines 6-9.

system is designed to meet the non-coincident peak demand of each circuit and substation[50] and thus, the incremental distribution-system load SDG&E adds is designed to meet non-coincident peak demand. For this reason, SEIA is mistaken when it claims that it would be inconsistent to use distribution-system loads in the calculation of marginal distribution demand costs but then bill customers based on non-coincident demand because the non-coincident demand drives the need for the incremental distribution-system load used in the development of the marginal distribution demand costs.

SEIA does raise an important question regarding the appropriate loads to use in the marginal distribution demand cost regression analysis. As stated above, SDG&E used its distribution-system load to measure incremental distribution load for use in the marginal distribution demand cost regression analysis. However, as explained in SDG&E witness Mr. Baranowski's direct testimony, the distribution planning department performs analysis to maintain reliability of the distribution system by developing circuit and substation load forecasts to determine the capacity upgrades required on the distribution system.[51] For this reason, SDG&E recognizes that the distribution loads used in the marginal distribution demand cost regression analysis should be based on the circuit and substation load forecasts used by the distribution planning department when determining the capacity upgrade needs, instead of the actual distribution-system loads, which are not the loads the distribution planning department relied on in their capacity upgrade analysis. Attachment G presents the marginal distribution demand cost results based on SDG&E's 2002-2016 distribution planning forecasted loads. Because the distribution planning forecasted loads are considered confidential data, these loads

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[50] SDG&E Direct Testimony of John Baranowski, Chapter 5, p. JB-1.

[51] SDG&E Direct Testimony of John Baranowski, Chapter 5, pp. JB-4 through JB-7.

are not presented in my rebuttal testimony but instead are identified in my Chapter 5 marginal distribution demand cost confidential rebuttal workpaper.

F. SDG&E Proposed Updated Marginal Distribution Demand Costs

Attachment G presents the updated marginal distribution demand costs based on the distribution-system loads that reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant, described in Section II.B.1, (b) 2002-2016 distribution-system loads, described in Sections III.B and III.C, and (b) 2014 and 2015 feeder and local distribution and substation costs from forecasted costs to actual costs, described in Section III.C. In addition, Attachment G presents the updated marginal distribution demand costs based on the distribution planning forecasted loads that reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant, described in Section II.B.1, (b) 2014 and 2015 feeder and local distribution and substation costs from forecasted costs to actual costs, described in Section III.C, and (c) 2002-2016 load data to reflect distribution planning forecasted loads, described in Section III.E.

SDG&E recommends that the Commission adopt the marginal distribution demand costs based on the distribution planning forecasted loads because this analysis correctly regresses incremental distribution investments by the forecasted loads that the distribution planning department determined were necessary to meet capacity upgrade needs. Attachment A reflects SDG&E's proposed updated marginal distribution costs in this proceeding based on the distribution planning forecasted loads.

IV. SDG&E PROPOSED UPDATED DISTRIBUTION REVENUE ALLOCATION

Attachment B presents the updated EPMC distribution revenue allocation proposed by SDG&E in this rebuttal testimony based on the current distribution revenues reflected in rates effective August 1, 2016.[52] This updated EPMC distribution revenue allocation is based on the SDG&E proposed updated marginal distribution customer and marginal distribution demand costs addressed above and presented in Attachment A. Marginal distribution customer cost revenues by customer class are developed by multiplying each class' unit marginal customer cost ($/customer/year) by the forecasted number of customers in that class. The rebuttal testimony of SDG&E witness Kenneth E. Schiermeyer provides the updates to the 2016 forecasted number of customers by customer class used to calculate SDG&E's proposed updated marginal distribution customer cost revenues in this testimony.[53] Marginal distribution demand cost revenues are developed by multiplying the unit marginal feeder and local distribution costs or substation costs ($/kW/year) by each class' non-coincident demand, applicable loss factors, and each class' effective demand factors ("EDFs") at the circuit or substation level with the revenues scaled to the 2016 distribution planning forecasted loads used to develop the marginal distribution demand costs. The 2016 forecasted non-coincident demand by customer class was updated consistent with the updated 2016 forecasted kWh sales proposed in the rebuttal testimony of Mr. Schiermeyer. The rebuttal testimony of SDG&E witness Leslie Willoughby provides the proposed updates to the EDFs by customer class that are used in the calculation of the marginal distribution demand cost revenues.[54]

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. SDG&E's proposed updated distribution revenue allocation by customer class is provided in Attachment B. Attachment B.1

[52] SDG&E Advice Letter 2922-E.
[53] SDG&E Rebuttal Testimony of Kenneth E. Schiermeyer, Chapter 4.
[54] SDG&E Rebuttal Testimony of Leslie Willoughby, Chapter 7.

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.

V. SUMMARY AND CONCLUSION

For the reasons stated above, the Commission should adopt: (a) SDG&E's proposed updated marginal distribution customer costs based on the Rental Method, as presented in Attachment A, that reflect the above described adjustments to the A&G Loading Factor for O&M Non-Plant, O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, and TSM RECC factors; (b) SDG&E's proposed updated marginal distribution demand costs, as presented in Attachment A, that reflect the above described adjustments to the A&G Loading Factor for O&M Non-Plant, 2014-2015 feeder and local distribution and substation costs to reflect actual costs, and 2002-2016 load data to reflect distribution planning forecasted loads; and (c) SDG&E's proposed updated distribution revenue allocations calculated based on SDG&E's proposed updated marginal distribution customer and demand costs, as described above and presented in Attachment B.

This concludes my prepared rebuttal testimony.

ATTACHMENT A

SDG&E PROPOSED UPDATED MARGINAL DISTRIBUTION COSTS

ATTACHMENT A (REBUTTAL)

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 Costs

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		$152.09			2
3	Small Commercial					3
4		0 - 5 kW	$323.57	$785.49		4
5		>5 - 20 kW	$588.70	$785.49		5
6		>20 - 50 kW	$1,232.43	$785.49		6
7		>50 kW	$1,709.43	$1,618.97		7
8		Average	$520.48	$904.55		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$2,272.23	$1,101.95	$7,365.07	11
12		500 - 12 MW	$5,452.08	$1,275.76	$12,851.85	12
13		> 12 MW		$1,923.27	$18,662.82	13
14		Average	$2,342.80	$1,190.27	$10,304.04	14
15						15
16	Agricultural					16
17		≤20 kW	$583.80	$918.69		17
18		>20 kW	$2,102.45	$1,054.85		18
19		Average	$989.98	$1,048.37		19
20						20
21	Lighting ($/Lamp/Year)		$11.87			21
22						22
23						23
24	Demand-Related Marginal Cost:					24
25	Feeders & Local Distribution Demand ($/kW/Year)		$60.72	$60.72		25
26						26
27	Substation Demand ($/kW/Year)		$19.67	$19.67		27
28						28
29	Total Demand-Related Marginal Cost ($/kW/Year)		$80.40	$80.40		29

Note: **Proposed Distribution Marginal Unit Costs**: the proposed distribution marginal unit costs are from the Chapter 5 Rebuttal Workpapers.

ATTACHMENT B

SDG&E PROPOSED UPDATED DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT B.1 (REBUTTAL)

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	$195,733	62.77%	$189,549	40.04%	$385,282	49.07%	1
2								2
3	Small Commercial	$67,902	21.78%	$57,583	12.16%	$125,485	15.98%	3
4								4
5	Medium/Large Commercial & Industrial	$42,598	13.66%	$218,908	46.24%	$261,506	33.30%	5
6								6
7	Agricultural	$3,698	1.19%	$6,078	1.28%	$9,775	1.24%	7
8								8
9	Lighting	$1,884	0.60%	$1,310	0.28%	$3,194	0.41%	9
10								10
11	System	$311,815	100.00%	$473,427	100.00%	$785,241	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 5 Rebuttal 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 (REBUTTAL)

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

		Updated Distribution Revenue Allocation				Current		
Line No.	Customer Class (A)	Distribution Allocation Factors (%) (B)	Non Marginal Distribution Revenue ($000) (C)	Marginal Distribution Revenue ($000) (D)	Total Distribution Revenue Allocation ($000) (E)	Total Distribution Revenue Allocation ($000) (F)	Percentage Change (%) (G)	Line No.
1	**Residential**	49.07%		$631,459	$631,459	$618,542	2.09%	1
2								2
3	**Small Commercial**	15.98%		$205,664	$205,664	$164,775	24.82%	3
4								4
5	**Medium/Large Commercial & Industrial**	33.30%	$8,254	$428,596	$436,850	$490,116	-10.87%	5
6								6
7	**Agricultural**	1.24%		$16,021	$16,021	$17,341	-7.61%	7
8								8
9	**Lighting**	0.41%	$4,912	$5,234	$10,147	$9,366	8.33%	9
10								10
11	**System**	100.00%	$13,166	$1,286,975	$1,300,141	$1,300,141	0.00%	11
12								12
13	Distribution Revenue Requirement ($000):	$1,300,141						13
14								14
15	Non Marginal Revenue Requirement Components ($000):							15
16	Lighting Facilities Charge Revenues:	$4,912						16
17	Standby Revenues:	$5,069						17
18	Distance Adjustment Fee Revenues:	$3,185						18

Note:

(1) **Distribution Revenue Allocation by Customer Class**: the distribution revenue allocation by customer class presented are from the Chapter 5 Rebuttal 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 August 1, 2016, pursuant to SDG&E Advice Letter 2922-E.
(4) **Distribution Revenue Requirement**: the $1,300,141,000 Distribution Revenue Requirement reflects the current distribution revenues being collected in rates effective August 1, 2016, 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 $5,069,000 are the standby revenues based on the forecasted standby determinants multiplied by the applicable current standby rates effective August 1, 2016, pursuant to SDG&E Advice Letter 2922-E.
(7) **Non-Marginal Distance Adjustment Fee Revenues**: Distance Adjustment Fees of $3,185,000 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 August 1, 2016, pursuant to SDG&E Advice Letter 2922-E.

ATTACHMENT B.3 (REBUTTAL)

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)	$12.67	$20.77		2
3		Demand-Related Marginal Cost ($/Non-Coincident kW)	$4.11	$6.74		3
4		Total - Residential			$631,459	4
5						5
6	Small Commercial					6
7		Customer Marginal Cost ($/Customer-Month)				7
8		Secondary				8
9		0 - 5 kW	$26.96	$44.19		9
10		>5 - 20 kW	$49.06	$80.40		10
11		>20 - 50 kW	$102.70	$168.32		11
12		>50 kW	$142.45	$233.47		12
13		Secondary Total	$43.34	$71.03		13
14						14
15		Primary				15
16		0 - 5 kW	$65.46	$107.28		16
17		>5 - 20 kW	$65.46	$107.28		17
18		>20 - 50 kW	$65.46	$107.28		18
19		>50 kW	$134.91	$221.12		19
20		Primary Total	$66.53	$109.04		20
21						21
22		Demand-Related Marginal Cost ($/Non-Coincident kW)				22
23		Secondary	$5.37	$8.80		23
24		Primary	$5.34	$8.75		24
25		Total	$5.37	$8.80		25
26						26
27		Total - Small Commercial			$205,664	27

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.
28					28
29	Medium/Large Commercial & Industrial				29
30					30
31	Secondary				31
32	≤500 kW	$189.35	$310.34		32
33	500 - 12 MW	$454.34	$744.64		33
34	Secondary Total	$195.58	$320.55		34
35					35
36	Primary				36
37	≤500 kW	$91.83	$150.50		37
38	500 - 12 MW	$106.31	$174.24		38
39	> 12 MW	$160.27	$262.68		39
40	Primary Total	$100.56	$164.82		40
41					41
42	Transmission				42
43	≤500 kW	$613.76	$1,005.92		43
44	500 - 12 MW	$1,070.99	$1,755.30		44
45	> 12 MW	$1,555.23	$2,548.96		45
46	Transmission Total	$962.43	$1,577.37		46
47					47
48	Demand-Related Marginal Cost ($/Non-Coincident kW)				48
49	Secondary	$8.63	$14.14		49
50	Primary	$8.58	$14.06		50
51	Total	$8.62	$14.12		51
52					52
53	Total - Medium/Large Commercial & Industrial			$428,596	53
54					54

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 ($000) (D)	Line No.
55	Agricultural				55
56	Customer Marginal Cost ($/Customer-Month)				56
57	Secondary				57
58	≤20 kW	$48.65	$79.73		58
59	>20 kW	$175.20	$287.15		59
60	Secondary Total	$78.62	$128.85		60
61					61
62	Primary				62
63	≤20 kW	$76.56	$125.47		63
64	>20 kW	$87.90	$144.07		64
65	Primary Total	$86.17	$141.24		65
66					66
67	Demand-Related Marginal Cost ($/Non-Coincident kW)				67
68	Secondary	$4.22	$6.92		68
69	Primary	$4.20	$6.88		69
70	Total	$4.22	$6.92		70
71					71
72	Total - Agricultural			$16,021	72
73					73
74	Lighting				74
75	Customer Marginal Cost ($/kWh)	$0.99	$1.62		75
76	Demand-Related Marginal Cost ($/kWh)	$5.37	$8.80		76
77	Total - Lighting			$5,234	77
78					78
79	Total-System				79
80	Customer Marginal Cost ($/Customer-Month)			$511,050	80
81	Demand-Related Marginal Cost ($/Non-Coincident kW)			$775,925	81
82	Total - System			$1,286,975	82

GRC Phase 1 Distribution Revenue Requirement:	1,300,141
Non-Marginal Revenue Requirement	13,166
Marginal Distribution Revenue Requirement Allocation	1,286,975
Marginal Customer Distribution Revenue Requirement	311,815
Marginal Demand-Related Distribution Revenue Requirement	473,427
Total Marginal Distribution Revenue Requirement	785,241
EPMC Allocation Factor	163.90%

Notes:

(1) **Distribution EPMC Rates and Revenues by Customer Class**: the distribution EPMC rates and revenues by customer class presented are from the Chapter 5 Rebuttal 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

REVISED A&G O&M NON-PLANT LOADING FACTOR

ATTACHMENT C (REBUTTAL)

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 AND DEMAND COSTS

Revised Administrative and General ("A&G") Loading Factors for Operations & Maintenance ("O&M") Non-Plant

Line No.	Description	2009	2010	2011	2012	2013	5-Year Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**ADMINISTRATIVE AND GENERAL EXPENSES**						
2	**(920) Administrative and General Salaries**	$14,290,294	$17,201,054	$21,679,499	$18,842,371	$24,202,412	
3	**(921) Office Supplies and Expenses**	$2,080,647	$7,655,150	$7,663,950	$9,849,366	$11,802,941	
4	**(922) Admin Expenses Transferred-Credit**	$4,725,196	$5,767,358	$7,422,656	$8,162,476	$7,659,598	
5	**(925) Injuries and Damages**	$10,774,639	$89,418,454	$163,950,485	$142,243,094	$312,716,691	
6	**(926) Employee Pensions and Benefits**	$51,996,223	$51,223,161	$59,183,873	$51,586,591	$57,170,990	
7	**(928) Regulatory Commission Expenses**	$15,627,039	$15,436,867	$14,022,098	$14,241,959	$17,713,245	
8	**(930.1) General Advertising Expenses**						
9	**(930.2) Miscellaneous General Expenses**	$17,221,322	$30,023,954	$18,584,549	$3,681,987	$4,409,948	
10							
11	**Total Non-Plant Related**	$107,264,968	$205,191,282	$277,661,798	$232,282,892	$420,356,629	
12	**(925.4) Wildfire Claims**	$0	$0	$79,279,814	$18,801,235	$215,737,954	
13	**Total Non-Plant Related Minus Wildfire Claims**	$107,264,968	$205,191,282	$198,381,984	$213,481,657	$204,618,675	
14							
15	**(923) Outside Services Employed**	$58,295,447	$60,411,738	$57,371,074	$60,418,785	$90,933,462	
16	**(924) Property Insurance**	$3,168,670	$3,646,154	$5,159,507	$7,093,526	$8,258,853	
17	**(927) Franchise Requirements**	$78,242,807	$78,596,651	$90,017,568	$91,227,453	$95,366,144	
18	**(929) Duplicate Charges-Cr.**	$1,727,837	$1,706,995	$1,860,286	$1,784,239	$1,950,344	
19	**(931) Rents**	$8,348,021	$8,606,273	$9,273,648	$10,932,665	$9,048,284	
20	**(935) Maintenance of General Plant**	$8,239,277	$7,570,736	$7,842,008	$8,639,949	$6,724,821	
21							
22	**Total Plant Related**	$154,566,385	$157,124,557	$167,803,519	$176,528,139	$208,381,220	
23							
24	**Total A&G**	$261,831,353	$362,315,839	$445,465,317	$408,811,031	$628,737,849	
25							
26	**Total O&M Expenses - Excludes Fuel Purchased Power, A&G & Water for Power**	613,857,832	553,554,697	576,219,404	633,846,596	790,175,352	
27							
28	**A&G Loading Factor Applicable to Non-Plant: Direct Testimony Proposal**	17.47%	37.07%	48.19%	36.65%	53.20%	38.51%
29							
30	**A&G Loading Factor Applicable to Non-Plant Excluding Wild Fire Claims: Rebuttal Proposal**	17.47%	37.07%	34.43%	33.68%	25.90%	$\boxed{29.71\%}$

ATTACHMENT D

REVISED TSM RECC AND PVRR FACTORS

ATTACHMENT D (REBUTTAL)

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

Revised Transformer, Services and Meter ("TSM") Real Economic Carrying Charge ("RECC") and Present Value Revenue Requirement ("PVRR") Factors

Line No.	2013 FERC Account	FERC Account Description	RECC Factors	PVRR Factors	Year-End 2013 Distribution Plant Additions	Weighted Average Factor SDG&E Direct Testimony	Weighted Average Factor UCAN Testimony	Weighted Average Factor SDG&E Rebuttal Testimony
1	**RECC Factors Used in Rental Method:**							
2	368.1	Line Transformers	9.19%		$26,220,836	49.31%	55.74%	63.05%
3	368.2	Protective Devices & Capacitors	14.99%		$5,946,023	11.18%		
4	369.1	Services Overhead	8.24%		$5,450,718	10.25%	11.59%	
5	369.2	Services Underground	8.31%		$8,635,866	16.24%	18.36%	20.76%
6	370.1	Meters	8.36%		$1,756,128	3.30%	3.73%	
7	370.2	Meter Installations	8.36%		$4,976,980	9.36%	10.58%	
8	371	Installations on Customer Premises	12.13%		$186,632	0.35%		
9	370.11	Smart Meters	11.72%		$1,756,128			4.22%
10	370.21	Meter Installations-Smart Meter	11.59%		$4,976,980			11.97%
11						100.00%	100.00%	100.00%
12		Weighted Average Customer-Related Distribution RECC (SDG&E Direct Testimony)	9.51%					
13								
14		Weighted Average Customer-Related Distribution RECC (Proposed by UCAN)	8.80%					
15		[Excludes FERC Account 368.2 and 371]						
16								
17		Weighted Average Customer-Related Distribution RECC (UCAN Proposal with SDG&E Adjustments)	9.40%					
18		[Also excludes FERC Account 369.1 and replaces 370.1 and 370.2 with 370.11 and 370.21]]						
19								
20	**SDG&E Rebuttal Proposal to Apply Individual TSM RECC Factors**							
21	**368.1**	Line Transformers		9.19%				
22	**369.2**	Services Underground		8.31%				
23								
24	**370.11**	Smart Meters		11.72%	$1,756,128			26%
25	**370.21**	Meter Installations-Smart Meter		11.59%	$4,976,980			74%
26		Weighted Average Meter RECC		11.62%				100%
27								
28								
29	**PVCC Factors Used in NCO Method:**							
30	368.1	Line Transformers		130.93%				
31	369.2	Services Underground		130.75%				
32	370.1	Meters		131.55%				
33								
34	**SDG&E Rebuttal Proposed PVCC Factors that Replace Meter PVCC with Smart Meter Average PVCC:**							
35	368.1	Line Transformers		130.93%				
36	369.2	Services Underground		130.75%				
37								
38	370.11	Smart Meters		112.99%	$1,756,128			26%
39	370.21	Meter Installations-Smart Meter		111.72%	$4,976,980			74%
40		Weighted Average Meter PVCC		112.05%				100%

ATTACHMENT E

REVISED ILLUSTRATIVE NCO METHOD CALCULATION RESULTS

ATTACHMENT E (REBUTTAL)

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
Revised 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		$100.27			2
3	Small Commercial					3
4		0 - 5 kW	$248.13	$488.80		4
5		>5 - 20 kW	$419.98	$488.80		5
6		>20 - 50 kW	$834.61	$488.80		6
7		>50 kW	$1,192.60	$876.88		7
8		Average	$374.17	$544.24		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$2,247.55	$1,104.28	$4,959.73	11
12		500 - 12 MW	$5,962.90	$1,345.30	$7,914.04	12
13		> 12 MW		$1,181.18	$11,192.54	13
14		Average	$2,323.33	$1,223.80	$6,565.82	14
15						15
16	Agricultural					16
17		≤20 kW	$428.04	$622.01		17
18		>20 kW	$1,206.77	$676.63		18
19		Average	$636.32	$674.03		19
20						20
21	Lighting ($/Lamp/Year)		$7.81			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).

ATTACHMENT F

REVISED 2002-2016 DISTRIBUTION-SYSTEM LOADS AND 2014-2015 FEEDER & LOCAL DISTRIBUTION AND SUBSTATION COSTS

ATTACHMENT F (REBUTTAL)

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

Revised Distribution-System Load and Distribution Demand Costs

Line No.	Year	Load Type	System Load (MW)	Transmission Load (MW)	Distribution-System Load (System Load minus Transmission Load) (MW)
1	2002	Weather-Normalized Actual	3,803	110	3,692
2	2003	Weather-Normalized Actual	3,913	118	3,795
3	2004	Weather-Normalized Actual	4,175	124	4,051
4	2005	Weather-Normalized Actual	4,226	107	4,119
5	2006	Weather-Normalized Actual	4,403	129	4,274
6	2007	Weather-Normalized Actual	4,484	111	4,373
7	2008	Weather-Normalized Actual	4,520	155	4,365
8	2009	Weather-Normalized Actual	4,353	119	4,234
9	2010	Weather-Normalized Actual	4,265	131	4,133
10	2011	Weather-Normalized Actual	4,404	109	4,295
11	2012	Weather-Normalized Actual	4,458	123	4,335
12	2013	Weather-Normalized Actual	4,634	131	4,503
13	2014	Weather-Normalized Actual	4,371	92	4,279
14	2015	Weather-Normalized Actual	4,248	95	4,154
15	2016	Forecast	4,551	112	4,438

16			Capacity-Related	Capacity-Related
17			Feeder & Local Distribution	Substation
18	Year	Cost Type	($000)	($000)
19	2002	Actual	$28,041	$12,577
20	2003	Actual	$27,113	$3,004
21	2004	Actual	$24,253	$10,439
22	2005	Actual	$32,478	$6,586
23	2006	Actual	$28,284	$5,097
24	2007	Actual	$36,326	$6,896
25	2008	Actual	$28,167	$4,816
26	2009	Actual	$29,540	$7,883
27	2010	Actual	$29,337	$8,613
28	2011	Actual	$25,164	$11,339
29	2012	Actual	$31,455	$4,065
30	2013	Actual	$28,962	$8,563
31	2014	Actual	$34,135	$13,819
32	2015	Actual	$47,554	$3,247
33	2016	Forecast	$67,855	$7,264

ATTACHMENT G

COMPARISON OF MARGINAL DISTRIBUTION DEMAND COSTS BASED ON DISTRIBUTION-SYSTEM LOADS VERSUS DISTRIBUTION PLANNING FORECASTED LOADS

ATTACHMENT G (REBUTTAL)

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

Comparison of Marginal Distribution Demand Costs Based on
Distribution-System Loads versus Distribution Planning Forecasted Loads

Line No.	Marginal Distribution Demand Costs Based on Updated Distribution-System Loads:	
1	**Feeder & Local Distribution Demand Costs ($/kW-Year)**	**$75.68**
2		
3	**Substation Demand Costs ($/kW-Year)**	**$19.45**

4	Marginal Distribution Demand Costs Based on Distribution Planning Forecast Loads:	
5		
6	**Feeder & Local Distribution Demand Costs ($/kW-Year)**	**$60.72**
7		
8	**Substation Demand Costs ($/kW-Year)**	**$19.67**